HECO T-4
DOCKET NO. 2006-0386

TESTIMONY OF

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Subject: Capacity Situation,
Fuel Expense,
Fuel-Related Expense,
Generation Efficiency, and
Fuel Inventory

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ross Sakuda and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as the Director of the Generation Planning Division in the Power Supply Services Department. My educational background and work experience are given in HECO-400.

Q. What will your testimony cover?

A. My testimony will cover the following:

1) HECO's capacity situation
2) test year fuel expense
3) fuel expense (oil only)
4) fuel-related expense
5) generation efficiency factor (heat rate)
6) fuel inventory

OVERVIEW

Q. What are the normalized 2007 test year estimates for the items in your area of responsibility?

A. The normalized test year estimates in my area of responsibility are:

Test Year 2007		Units
1) Fuel Expense	542,961,000	$
a) Fuel Expense (Oil)	536,833,000	$
b) Fuel-Related Expense	6,128,000	$

2)	Fuel Price		See HECO-402
3)	Purchased Energy Forecast	3,372.7	GWh
4)	Efficiency Factor (Sales Heat Rate)	0.011226	MBtu/kWh sales
5)	Fuel Inventory	52,706,000	$

The units of measure used above include barrels ("bbl"), which is equal to 42 gallons, gigawatt-hours ("GWh"), and millions of British thermal units per kilowatt-hour ("MBtu/kWh).

HECO's CAPACITY SITUATION

Q. What is HECO's forecast for sales in the test year?

A. As Mr. George Willoughby indicates in HECO T-2, the Company forecasts sales to be 7,720,800 megawatt-hours ("MWh") in the 2007 test year.

Q. Does HECO forecast that sales will continue to grow beyond the test year?

A. Yes. HECO forecasts that both sales and peak demand will continue to grow in future years. The following table summarizes HECO's August 2006 sales and peak forecast.

	Sales reduced by Future DSM (MWh)	Peak Demand reduced by Future DSM (MW-net)
2007	7,720,800	1,287
2008	7,831,300	1,294
2009	7,921,300	1,310
2010	8,016,000	1,324
2011	8,069,200	1,333

(See HECO-WP-201 for the HECO August 2006 Sales and Peak Update and refer to the table of Sales on page 15, and the table of net peaks on page 43.)

The peak forecast includes the peak reduction benefits of energy efficiency demand-side management ("DSM") programs and assumes that HECO will need to serve the standby loads of Chevron, Tesoro and Pearl Harbor.

Q. How does HECO plan to meet consumers' increasing need for electricity?

A. HECO plans to meet consumers' increasing need for electricity through a portfolio of energy solutions. This portfolio includes the following components:

1) Maintaining and improving the availability of HECO's existing generation as addressed by Mr. Dan Giovanni in HECO T-6.
2) Continuation of the existing energy efficiency DSM programs, with substantial enhancements and modifications as addressed by Mr. Alan Hee in HECO T-9. The impact of these programs is reflected in the sales and peak data submitted by Mr. George Willoughby in HECO T-2.
3) Implementation of the residential direct load control program, approved in Docket No. 03-0166, and the commercial and industrial direct load control program, approved in Docket No. 03-0415, and proposed modifications to these two load management programs, as addressed by Mr. Hee in HECO T-9.
4) Installation of distributed generator ("DG") units at HECO sites and distributed standby generators ("DSG") at customer sites, as addressed in HECO T-6 by Mr. Giovanni.
5) Implementation of renewable energy projects.
6) Installation of a 113 MW simple cycle combustion turbine in 2009.

Q. What progress has HECO made in the renewable energy area?

A. HECO's efforts to acquire renewable energy were discussed extensively by Mr. Arthur Seki in HECO T-5 and HECO RT-5 in Docket No. 05-0145 (Campbell Industrial Park Generating Station). These efforts include the following:

- Wind Energy – Mr. Seki explained HECO's significant efforts to install a wind farm in the 25 to 50 MW range on a ridge above the Kahe Power Plant. At community meetings held on July 19, 20 and 21, 2005, strong concerns were expressed about the impact of the proposed wind farm on archaeological and cultural sites in the area, as well as the potential loss of panoramic views of the coastline. Further, while the City and County of Honolulu expressed general support for wind energy as a resource, it announced in September 2005 that it would not issue government permits for the proposed Kahe wind farm based on community concerns. In light of this opposition, HECO determined that it is not practical to proceed with the Kahe wind farm, and is exploring other alternatives.
- Biofuels – Mr. Seki described HECO's substantial efforts in the biofuels area. HECO has an active multi-year, multi-phase research and development program to examine biofuels. HECO is willing to commit to using 100% biofuel in its proposed Campbell Industrial Park combustion turbine generating unit, as described in its Stipulation with the Division of Consumer Advocacy, Exhibit A, "Position on Biofuels for the New Combustion Turbine Unit", filed on December 4, 2006 in Docket No. 05-0145.
- Photovoltaic Systems – HECO will install photovoltaic ("PV") systems at HECO's Ward Avenue facility. PV cells convert sunlight directly into electricity. HECO plans to issue a request for proposal ("RFP") in January 2007 to solar-energy companies to build, own and operate one or more PV systems on the rooftop of the Archer Substation located at HECO's Ward Avenue facility. HECO would purchase the PV electricity and would have an option to acquire the PV system after several years. Based on HECO's

preliminary assessment, PV systems totaling approximately 155 kilowatts of direct current (kW_{dc}) power output could be accommodated on the Archer Substation rooftop. The project is planned to be in operation by December 1, 2007.

- Renewables from Independent Power Producers ("IPP") – HECO will evaluate proposals made by IPPs, such as a potential ocean thermal energy conversion ("OTEC") project off Kahe Point, as identified in the HECO, HELCO and MECO Renewable Portfolio Standard Status Report filed with the Commission on June 27, 2005.

Q. In your 2005 Test Year Rate Case testimony and information responses, you addressed HECO's capacity situation, as reported in HECO's 2004 and 2005 Adequacy of Supply Reports. Please provide an update as to the status of HECO's reserve margin shortfall situation.

A. In its 2006 AOS Report filed March 6, 2006, HECO indicated that it had sufficient firm generating capacity on its system to meet the forecasted load, but also indicated that HECO may not, at times, have sufficient capacity to cover for the loss of the largest unit or for multiple generating unit outages. Thus, HECO anticipated reserve capacity shortfalls in 2006 and projected these shortfalls to continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation its next central station generating unit.

HECO estimated that approximately 170 MW of additional peak load reduction measures and/or generating capacity would be needed in 2006 in order to maintain generating system reliability at or above HECO's reliability guideline. This is in addition to (1) the projected successful implementation of the residential and commercial load management DSM programs for which HECO has already obtained approval, and (2) approval for, and successful implementation of, the Interim DSM Proposals in July 2006 and the enhanced energy efficiency DSM programs and load management program modifications beginning in 2007. The reserve capacity shortfall was projected to be approximately 170 to 200 MW in the 2007 to 2009 period.

In its 2006 AOS Report, HECO also considered three alternate scenarios in addition to the base case. Under the alternate higher load scenario, higher than forecast load growth and/or less than anticipated impacts of energy efficiency DSM, load management DSM, and CHP will cause the reserve capacity shortfall to increase, reaching approximately 180 MW in 2006, and 230 MW in 2009. Under the alternate lower load scenario, lower than forecast load growth and/or more than anticipated impacts of energy efficiency DSM, load management DSM, and CHP will cause the reserve capacity shortfall to decrease, reaching approximately 110 MW in 2006, and 140 MW in 2009. With the better EFOR scenario, efforts to improve HECO generating unit EFOR rates will cause the reserve capacity shortfall to decrease, to approximately 120 MW in 2006, and 160 MW in 2009.

Since the time of the March 2006 analysis, HECO's latest peak load forecast (issued in August 2006, as indicated above) was reduced by approximately 67 to 92 MW in the period from 2006 to 2010. The impact of this change, along with updates in other planning assumptions, has reduced the projected estimate of the reserve capacity shortfall to approximately 120 MW by 2009, before installation of the new combustion turbine at Campbell Industrial Park [90 MW to 130 MW in the years 2006 to 2010, assuming the 113 MW combustion turbine is not installed in 2009 as planned]. (This includes the impact of using leased distributed generating units at substations to mitigate the shortfall pending the installation of new long-term capacity.)

Q. Has HECO provided any update of its capacity situation based on the latest peak load forecast?

A. Yes, my rebuttal testimony (HECO RT-2, pages 2 to 11) in Docket No. 05-0145 provided an updated generating system reliability analysis similar to that included in HECO's 2006 AOS Report. (See Section 4.3.1 on pages 30 to 32 of the March 2006 AOS report.) The results of the updated analysis indicated that even with the lower peak forecast of August 2006 and additional distributed generation ("DG") to be installed at HECO sites, HECO's reserve capacity shortfall ranged from 90 MW to 130 MW in the years 2006 to 2010, assuming the 113 MW combustion turbine is not installed in 2009 as planned. The results of the analysis, based on the revised assumptions, indicate that HECO will continue to experience a reserve capacity shortfall and has a continued need for additional firm generating capacity, even with the lower sales and peak forecast and additional DG.

Moreover, it is likely that HECO will still have a reserve capacity shortfall after the proposed combustion turbine is installed in 2009 at Campbell Industrial Park (predicated on Commission approval in Docket No. 05-0145).

Q. Has the actual peak for 2006 exceeded the August 2006 sales and peak forecast?

A. Yes. On August 28, 2006, HECO's day peak was 1,266 MW-net (or 1,315 MW-gross), which exceeds the system peak projection in the August 2006 sales and peak forecast. On this date, the cogenerating units at the refineries (Chevron and Tesoro) were operating and serving at least a portion of their own demand. Had their cogenerating units not been operating, the adjusted total demand on the system would have been 1,290 MW-net. The projected system peak for 2006 was 1,278 MW-net, assuming HECO was serving the refinery loads. Therefore, the day peak on August 28, 2006 exceeded the 2006 system peak forecast by approximately 12 MW.

Q. What is the impact of a reserve margin shortfall situation?

A. As indicated in HECO's recent AOS Reports, until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and more frequent, longer duration reserve capacity shortfalls. The actual risk of generation-related customer outages depends, among other factors, on (1) the actual peaks experienced by the system, (2) success in implementing the DSM programs and utility CHP projects, and customer participation in these programs, (3) the ability of HECO and its IPP partners to minimize unplanned or extended outages of existing generating units, and (4) the extent to which mitigation measures can be implemented. If actual peaks, due to weather impacts or other factors, are higher than forecasted, or if generating units experience higher forced outage rates, and/or more and longer maintenance outages, the risk of generation-related customer outages will increase.

Q. As a follow-up to its AOS Reports, what steps has HECO taken to mitigate the potential impact of the reserve margin shortfall situation?

A. As indicated in the 2006 AOS Report, HECO has taken a number of actions to minimize the risk of generation-related shortfalls, which include implementing the approved load management DSM programs, implementing interim DSM proposals with Commission approval in advance of the Commission's ultimate ruling on the enhanced energy efficiency DSM programs proposed in Docket No.

05-0069, working to maintain or improve the availability of HECO generating units, working to maintain or improve the availability of Independent Power Producers' generating units, negotiating and obtaining approval of the Kalaeloa amendments adding 28MW of firm capacity in 2005, installation of 14.8 MW of DG at substation sites in 2005, another 9.8 MW in 2006, and an additional 4.9 MW planned for the first quarter of 2007,[1] and initiation of permitting and design of the next generating unit so that it can be installed by 2009. HECO also indicated that it was evaluating to file a request for approval to commit funds for a second combustion turbine at Campbell Industrial Park.

Q. Has HECO's need for additional firm capacity resulted in any shortfalls of generating capacity?

A. Yes, it has. On June 1, 2006, HECO experienced an actual shortfall of generating capacity. Prior to the June 1 event, four HECO generating units (Waiau Units 3, 4 and 5 and Kahe Unit 2) were out of service on scheduled maintenance. On May 31, the CT-2 operated by Kaleloa Partners, L.P. ("Kalaeloa") experienced an emergency shutdown. At around noon on June 1, Kalaeloa's CT-1 experienced a forced outage. About two hours later, Waiau Units 9 and 10 tripped out of service as their voltage regulators exceeded their operating limits. To prevent other generating units from tripping out of service, load from the system was manually shed, interrupting service to approximately 29,000 customers.

Q. Please briefly summarize this section of your testimony.

A. HECO continues to experience a reserve capacity shortfall, and that shortfall is projected to range from 90 MW to 130 MW in the 2006 to 2010 timeframe even

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[1] These DGs are intended as temporary measures to help mitigate the reserve capacity shortfall. Their air permits allow them to run for a limited number of hours over each rolling 12-month period. They are not a substitute for the capacity that will be provided by the combustion turbine and are not planned as a long-term resource to meet customer demand.

with the lower forecast of peak demand (assuming the 113 MW combustion turbine is not installed in 2009 as planned). HECO continues to pursue a portfolio of energy resources, including energy efficiency DSM, load management programs, DG and DSG, renewable energy and a 113 MW simple cycle combustion turbine, to meet the growing demand for electricity. It is likely that HECO will still have a reserve capacity shortfall after the proposed combustion turbine is installed in 2009 at Campbell Industrial Park (predicated on Commission approval in Docket No. 05-0145).

FUEL EXPENSE

Q. What is HECO's normalized test year estimate of fuel expense?

A. HECO's normalized test year estimate of fuel expense is $536,833,000, as shown in HECO-401. This expense represents the cost of fuel required by HECO to produce the energy required above purchased power to meet the projected needs of its customers.

Q. What are the primary determinants of fuel expense?

A. There are two primary determinants of the test year fuel expense: fuel price and projected fuel consumption (i.e., the quantity of fuel needed to produce the required energy).

Fuel Prices

Q. What are the test year fuel prices?

A. HECO's test year prices for Low Sulfur Fuel Oil ("LSFO") and diesel oil are shown in HECO-402.

Q. How were these prices determined?

A. For test year 2007, the fuel prices for HECO are based on the August 2006 contract prices, which were the latest available contract prices at the time this testimony was being prepared.

Q. What are the contract prices based on?

A. For LSFO, the price is based on the average daily market price of the Pacific Basin's most commonly traded grade of low sulfur fuel oil, Singapore/Indonesian region low sulfur waxy residual ("LSWR") fuel oil and other components including taxes. The price of LSWR is indexed to a basket of third-party market price assessments including Platt's Oilgram Price Report, RIM Products Intelligence Daily, ARGUS Asia Pacific Products and Far East Oil Prices. The base price of LSFO effective for the following month is based on the average of business day price assessments for the respective dates of publication between the 21st day of the second preceding month and the 20th day of the preceding month of the volume of LSFO nominated to be received during that month.

Because HECO projects from both Chevron and Tesoro, that it will receive LSFO from both suppliers, the Company has weighted the LSFO price by the volumes expected to be purchased through each contract during the test year. The resulting price shown in HECO-402 is based on August 2006 contract prices.

For diesel oil, the price is based on the average daily market price of West Coast Pipeline, Los Angeles Low Sulfur Diesel as assessed by Platt's Oilgram Price Report for dates between the 21st day of the second preceding month and the 20th day of the preceding month the diesel is purchased.

Q. When do these existing Chevron and Tesoro contracts expire?

A. The two LSFO contracts and the diesel contract expire on December 31, 2014.

Q. How are these fuel prices used in this proceeding?

A. Fuel prices are used in the calculation of:

1) fuel expense,
2) purchased energy expense, and
3) fuel inventory, which is covered later in my testimony.

Fuel expense is fuel consumption times fuel prices. (See HECO-404.) Purchased energy expenses, discussed by Mr. Daniel Ching in HECO T-5, are also calculated using fuel prices. The purchased energy expenses are listed for each IPP in HECO-506. Fuel inventory is the number of barrels in inventory times fuel prices. (See HECO-408.) This is consistent with other HELCO and MECO rate cases.

<u>Fuel Consumption</u>

Q. What is the estimated test year fuel consumption?

A. An estimated 8,030,246 barrels of LSFO will be burned in HECO's steam generators to produce 4,693,200 MWh of energy. HECO's combustion turbines will burn an estimated 101,195 barrels of diesel oil to produce 19,100 MWh of energy. HECO DGs and DSGs will burn an estimated 40,109 barrels of diesel oil to produce 23,000 MWh of energy. (See HECO-404 for barrels of fuel consumption, and HECO-406 for energy generated by each type of fuel.)

Q. How is HECO's fuel consumption determined?

A. The fuel consumption in the test year is determined through the use of a computer production simulation model. The model, P-MONTH, is a production simulation program supplied by the P Plus Corporation ("PPC"). This model simulates the chronological, hour-by-hour operation of HECO's generation system by dispatching (mathematically allocating) the forecasted hourly kilowatt load among the generating units in operation. Unit commitment and dispatch levels are based on fuel cost, transmission loss (or "penalty") factors and any transmission system requirements. The load is dispatched by the model such that the overall fuel expense of the system is minimized (i.e., "economic dispatch"). The model calculates the fuel consumed using the unit dispatch described above, based on the load carried by a unit and the unit's efficiency characteristics. The total fuel consumed is the summation of each unit's hourly fuel consumption. The simulation's results are then adjusted using a calibration factor for each power plant and for the combustion turbines.

Q. Is this the same production simulation model that HECO used in its 2005 test year rate case?

A. Yes. The P-MONTH production simulation model was used in the HECO 2005 test year rate case (Docket No. 04-0113). The same model was also used in the MECO test year 1999 rate case (Docket No. 97-0346), the HELCO test year 1999 rate case (Docket No. 97-0420), the HELCO test year 2000 rate case (Docket No. 99-0207), and the HELCO test year 2006 rate case (Docket No. 05-0315). P-MONTH is supplied by an outside vendor that has dedicated staff to maintain and update the program. As a result, the program algorithms used in this model are consistent with current industry standards.

Q. What generating facilities are subject to HECO's dispatch control?

A. HECO has dispatch control over its own central station generating units at Kahe, Waiau, and Honolulu Power Plants, as well as HECO and customer-cited DG and DSG units. HECO also has dispatch control over the generating facilities at Campbell Industrial Park ("CIP") operated by Kalaeloa, AES Hawaii ("AES"), and Honolulu Resource Recovery Venture ("H-POWER"), from which HECO purchases firm capacity and energy pursuant to power purchase agreements ("PPAs") approved by the Commission.

Q. How are these generating units dispatched by the production simulation model to determine the estimated energy to be produced by HECO's generating units and purchased from Kalaeloa and AES?

A. The HECO, Kalaeloa and AES units are dispatched on the basis of economic dispatch, subject to any applicable generation or system constraints. The energy to be purchased from H-POWER was separately forecast (as addressed by Mr. Ching in HECO T-5), based on the power dispatch schedule for the unit (which takes into account the minimum dispatch provisions of the H-POWER PPA).

Q. Did the Company's production simulation assume any unusual system constraints?

A. No. For this rate case, the production simulation assumed that there were no unusual system constraints present.

Q. Have there been any major changes to HECO's generating system since HECO's 2005 test year rate case (Docket No. 04-0113) that would have a significant impact on the determination of fuel consumption for the test year 2007?

A. No. There have been no significant changes. In HECO's previous rate case, the additional 28 MW from Kalaeloa and the additional 14.8 MW from DGs at HECO sites were already reflected in the determination of fuel consumption. In this docket, an additional 9.8 MW of DG to be installed at HECO sites in 2006, an additional 4.9 MW of DG targeted for installation in 2007, and an additional 1.7 MW of DSG targeted for installation in 2007 are being included, but the impact on fuel consumption is relatively small.

Q. What are the key inputs to the P-MONTH production simulation model?

A. The key inputs to the production simulation model, when applied to the HECO system, are as follows:

1) energy and hourly load to be served by the HECO system
2) energy and hourly load to be served by firm and non-firm purchased power producers
3) load carrying capability of each HECO and firm power producer generating unit
4) efficiency characteristics of each HECO generating unit
5) pricing formulas for the fuel and variable operations and maintenance ("O&M") components of the Kalaeloa and AES energy charges
6) planned maintenance schedules for the generating units
7) estimated forced outages rates for HECO, Kalaeloa and AES units
8) prices for fuels used by the HECO generating units

Q. Is DG and DSG fuel consumption included in your estimate of fuel expense?

A. Yes, it is.

Q. What assumptions did the Company use to determine the DG and DSG fuel consumption?

A. The Company assumed that a total of approximately 29.5 MW of DG capacity and 1.7 MW of DSG capacity would be in operation by the end of 2007 and 23.0 GWh of energy would be generated (equivalent at the system level) by these units. Additional information about the DG and DSG units is included in Mr. Giovanni's testimony in HECO T-6.

Q. Is combined heat and power ("CHP") fuel consumption and fuel expense included in the test year?

A. No, it is not. HECO does not anticipate that any utility CHP will be installed on Oahu in 2006 or 2007.

Energy and Hourly Load to be Served by the System

Q. How is the energy to be served by the system determined?

A. The total net system input, or total net energy required by the system, is determined based on the forecasted estimates for sales, Company use, and system losses for the test year. For the base case test year 2007, total net system input is estimated to be 8,109.2 GWh. (See HECO-403, line 5.)

Q. How is the Company use for the test year determined?

A. Company use (or Company No Charge Energy) is determined from a five-year (2001-2005) average of recorded Company use. The Company use for the test year is 15.4 GWh as shown in HECO-403, line 2.

Q. How are the system losses for the test year determined?

A. System losses are determined from a five-year average of system losses as shown on HECO-WP-403, page 2. The five-year average of losses as a percentage of net-to-system energy is 4.60%. This percentage was multiplied by the test year net-to-system energy. The system losses for the test year are 373.0 GWh as shown in HECO-403, line 4.

Q. How is the system's hourly load determined?

A. The hourly load on the HECO system is based on the actual 2005 hourly load adjusted for the annual sales and peak forecast, as shown in HECO-WP-201, and for the Company use and system losses.

Q. How is the system's hourly load adjusted for Company use and system losses?

A. Company use and system losses are added to the sales to derive the total net system energy as shown in HECO-403, line 5. This total net-to-system energy is used to estimate hourly loads based on historical load patterns.

Energy and Hourly Load to be Served by Firm
and Non-Firm Purchased Power Producers

Q. What is the source of the test year 2007 purchased power estimate for HECO?

A. Three methods were used to determine the purchased power estimate:

1) modeling the firm, dispatchable units (Kalaeloa and AES) in the production simulation,
2) estimating the total energy purchased from the firm, scheduled dispatch H-POWER unit based on historical information, and
3) estimating the total energy purchased from non-firm units (Chevron and Tesoro) from historical production.

The purchased energy estimates for H-POWER, Chevron and Tesoro were supplied by the Power Purchase Division. Mr. Ching will discuss these estimates in HECO T-5.

Q. Is HECO is seeking rate recovery [in this rate case] for the estimated cost of purchased energy from the Archer Substation PV facility?

A. Once a PV power supplier has been selected through the planned RFP process, power purchase expenses and the production simulation may be adjusted at the next available opportunity to reflect the estimated PV energy purchases in 2007, although it is not expected that the purchased energy amount or expense would be significant in 2007 given the estimated in-service date of December 1, 2007.

Q. How is the hourly load served by purchased power producers determined?

A. The hourly loads for Kalaeloa and AES are determined through dispatch of the units in the production simulation. Hourly operating costs are developed for Kalaeloa and AES based on their contract pricing formulas.

The estimated energy dispatched from Kalaeloa and AES by the production simulation model has been used in HECO T-5 to develop purchased power expense estimates for these two IPPs.

The hourly loads for non-firm purchased power producers (Chevron and Tesoro) are modeled at a constant level throughout the 24-hour day period, seven days per week.

Load Carrying Capability of HECO Units

Q. What is the load carrying capability of each HECO generating unit?

A. The load carrying capability of each unit is the ability to generate electricity to supply the load from a unit's minimum rating to its normal top load rating ("NTL"). In actual operations, HECO uses an Energy Management System ("EMS") to control the dispatch of the units. In EMS, each generating unit is limited to a range of output through which the machine can be operated predictably without reconfiguring the plant from normal operation. In general, EMS limits match NTL ratings.

A list of HECO and non-utility, firm power IPP generating unit load carrying capabilities is provided in HECO-WP-406, page 1.

Efficiency Characteristics of HECO Generating Units

Q. What are a generating unit's "efficiency characteristics"?

A. The "efficiency characteristics" of a generating unit are the relationship between fuel input to the unit and the electrical output of the unit. This relationship can be expressed as a second-order equation in the form of:

$$\text{Fuel input} = A + (B*\text{Load}) + (C*\text{Load}^2)$$

where Load is the operating level in MW.

The values for A, B, and C are the "heat rate constants" for the generating unit.

Q. How were the HECO unit efficiency characteristics determined?

A. The unit efficiency characteristics for the HECO generating units were developed from test data. The fuel consumption rates at various output levels have been measured, and the "heat rate constants" of the units were determined by fitting a curve of fuel consumption versus output level through the test data points. The "heat rate constants" determined are used as inputs in the production simulation model. The heat rate constants are shown in HECO-WP-406, page 2, and are consistent with those used in the rebuttal testimony of its last rate case, Docket 04-0113.

Pricing Formulas for the Kalaeloa and AES Energy Charges

Q. How are the pricing formulas for Kalaeloa and AES modeled in the production simulation?

A. The contractual payment provisions for each producer were used to develop cost curves for the production simulation model. Each of the Kalaeloa and AES pricing formulas, in essence, expresses the cost per kWh of energy and variable O&M as a function of the unit's output. This relationship is approximated by a second order equation of the form:

Fuel and variable O&M cost = A + B*Load + C*Load2

where Load is the operating level in MW.

A curve-fitting technique is used to determine the coefficients A, B and C. These coefficients are then used to represent the cost curve of the Kalaeloa and AES units in the production simulation.

Planned Maintenance Schedules

Q. What is the source of the 2007 test year planned maintenance schedule?

A. HECO's Power Supply O&M Department developed the test year planned maintenance schedule. The test year planned maintenance schedule is discussed further by Mr. Giovanni in HECO T-6. HECO is using a 2007 planned maintenance schedule dated July 21, 2006.

Q. What is the source of the calibration year planned maintenance schedule?[2]

A. The planned maintenance schedule for the calibration year uses the actual maintenance and overhaul days for 2005.

Forced Outages and Maintenance Outages

Q. What is the source of the 2007 test year forced outage rates for HECO's generating units and the Kalaeloa and AES units?

A. The forced outage rates for the 2007 test year for HECO's generating units were the forward-looking EFOR values used in HECO's 2006 AOS report. An extensive discussion of the derivation of the forward-looking EFOR values is provided in Appendix 7 of the 2006 AOS report. (See HECO-WP-406, page 3.) The forced outage rate 1.5% for Kalaeloa is based on recent experience. My rebuttal testimony in HECO RT-2 on page 6 in Docket No. 05-0145 explained that the heat recovery steam generators at Kalaeloa have been experiencing an increasing number of tube failures and that a 1.5% forced outage rate is more representative of future expectations.

Q. What are maintenance outages?

A. Maintenance outages are outages other than forced outages or planned overhauls. Generally, an outage is labeled as a maintenance outage when a unit must be repaired, but does not need to come off-line right away. (See also the testimony of Mr. Giovanni in HECO T-6.) Maintenance outages were included in the planned maintenance schedule.

Q. What is the source of the calibration year forced outage rates for the HECO

[2] As explained later in this testimony, the calibration year is the recorded year used to determine the Company's calibration factors. For this rate case, the calibration year is 2005.

system?

A. Forced outage rates for the calibration year are based on the actually recorded forced outage rates by unit in 2005.

Fuel Prices

Q. Are the fuel prices used in the production simulation model the same ones described earlier in this testimony?

A. Yes. The fuel prices used in the production simulation model were as described earlier in the testimony. The fuel prices for the calibration year are based on the actual prices paid for fuel by HECO in 2005.

Q. What are the results of the test year production simulation?

A. The results of the test year production simulation (net MWh) can be seen in HECO-WP-404, page 1 (net MWh).

Q. Are the results of the HECO production simulation checked against actual historical operations?

A. Yes. For this rate proceeding, the results of the HECO production simulation are calibrated against data for actual operations for the January through December 2005 period. This is the most recent available historical data for a full calendar year at the time the production simulation was developed for the test year. Historical data including load data, planned maintenance schedules, forced outages, fuel prices, and unit efficiency characteristics are input into the production simulation model. The model is run in a manner to simulate how the system was actually run in the historical year. The model results are compared to the historical recorded data on a monthly and annual basis.

The differences between the heat rates from the calibration production simulation described above and from actual operations are due to "real-world" conditions which cannot be completely duplicated by a production simulation.

Q. How are these differences incorporated into the determination of the test year's fuel consumption?

A. The differences are accounted for in the test year fuel consumption by applying calibration factors to the production simulation's output for Kahe, Waiau (LSFO portion), Honolulu power plants, as well as the diesel-fired combustion turbines at Waiau. The derivation of the calibration factor for the test year is shown in HECO-WP-404, page 1. The "Simulated" heat rate is calculated from the Btu consumption and net generation figures produced by the production simulation. The "Actual" heat rate is based on recorded January through December 2005 data. The calibration factor is calculated by dividing the Actual heat rate by the Simulated heat rate.

<u>Calibration Factor</u>

Q. What is a calibration factor?

A. A calibration factor is a constant number that can be greater than, equal to, or less than 1.00. The test year heat rate (in Btu/kWh) determined by the production simulation is multiplied by this factor.

Q. What is the purpose of the calibration factor?

A. The purpose of the calibration factor is to adjust the fuel consumption determined by the production simulation for actual operating conditions that cannot be completely duplicated by the computer model.

Q. How is a calibration factor determined?

A. As described above, the calibration factor is determined by simulating the output of the utility production system for a recorded year, called a "calibration year," and finding the ratio between the computer model outputs and recorded amounts.

Q. Please identify the actual operating conditions that cannot be completely duplicated by the computer model.

A. The actual operating conditions that cannot be completely duplicated by the computer model include, but are not limited to, the following:

a) temporary unit deratings

b) changes in unit commitment

c) unpredictable nature of intermittent, as-available resources

d) actual system conditions

f) actual system load

g) steam turbine and combustion turbine performance

Each of these factors are discussed in detail in my rebuttal testimony in Docket No. 99-0207, HELCO test year 2000 rate case, HELCO RT-4, page 17, line 15, to page 30, line 8. As the HECO and HELCO systems are not identical, the magnitude of the calibration factor may differ. However, the contributing factors which result in the need for a calibration factor are similar – there are common, practical limitations to duplicating actual conditions for any system.

Q. In which previous dockets has the Commission approved use of a calibration factor?

A. The Commission accepted results of production simulations that used calibration factors in the following HECO, HELCO and MECO rate cases:

1) Docket No. 7700, HECO Test Year 1994

2) Docket No. 7766, HECO Test Year 1995

3) Docket No. 94-0140, HELCO Test Year 1996

4) Docket No. 94-0345, MECO Test Year 1996

5) Docket No. 96-0040, MECO Test Year 1997

6) Docket No. 97-0346, MECO Test Year 1999

7) Docket No. 99-0207, HELCO Test Year 2000

8) Docket No. 04-0113, HECO Test Year 2005

In Docket No. 99-0207, the Consumer Advocate opposed the use of a calibration factor in that docket. However, Decision and Order ("D&O") No. 18365 (pages 18-19), issued on February 8, 2001, stated:

> The commission concludes that in lieu of elimination, it will allow for the continued use of the calibration factor. HELCO must, however, on a going forward basis, file with the commission and Consumer Advocate, annual reports identifying the actual system value for each year, the computer model results, and the adjustment resulting from the calibration factor. This should supply the Commission and Consumer Advocate with appropriate data and information to more effectively address this issue in future rate cases.

HELCO has complied with the Commission's order and has filed calibration factor reports for the years 2000 through 2006.

Q. Is HECO also required to file annual calibration factor reports to the Commission?

A. Yes. In HECO's test year 2005 rate case, in Docket No. 04-0113, HECO filed a Stipulated Settlement Letter ("Settlement Letter") on September 16, 2005, that documented certain agreements between HECO, the Division of Consumer Advocacy ("Consumer Advocate") and the Department of Defense ("DOD") regarding matters in HECO's 2005 test year rate case proceeding.[3] Paragraph 4.a. of the Settlement Letter stated, "For the purposes of Settlement, the Consumer Advocate and the DOD agree with HECO's proposal to incorporate use of the 2004 calibration factor in determining test year fuel expense, as HECO in turn

[3] The Settlement Letter stated in part on page 1, "The agreements are for the purpose of simplifying and expediting this proceeding, and represent a negotiated compromise of the matters agreed upon, and do not constitute an admission by any party with respect to any of the matters agreed upon herein."

agrees to the same calibration factor reporting requirements that were required of HELCO in Docket No. 99-0207." Interim Decision and Order No. 22050 in Docket No. 04-0113 stated on page 7, "Where the Parties agree, we accepted such agreement for purposes of this Interim Decision and Order."

Q. What were HECO's reported calibration factors?

A. My rebuttal testimony in HECO RT-4, HECO reported a system-wide calibration factor of 1.0275. In its first annual calibration factor report, filed with the Commission on March 15, 2006, HECO reported a system-wide calibration factor of 1.024.

Q. What is the calibration factor that HECO is using in this proceeding to determine the test year fuel consumption?

A. HECO is using the following calibration factors, broken down by power plant and fuel type and based on the Monte Carlo technique, which I will discuss later in my testimony:

Power Plant	Calibration Factor
Kahe Power Plant (LSFO)	1.0144
Waiau Power Plant Steam Units (LSFO)	1.0164
Waiau Power Plant Combustion Turbines (Diesel Fuel)	1.0859
Honolulu Power Plant (LSFO)	0.9721
Total HECO System	1.0199

Q. Did HECO use calibration factors broken down in this fashion in its 2005 test year rate case and in its first calibration factor report filed with the Commission?

A. Yes. In its 2005 test year rate case (see HECO filing, dated May 5, 2005, titled "HECO 2005 Test Year Rate Case – Updates, Attachment 2, page 1) and in its first calibration factor report filed with the Commission on March 15, 2006, HECO reported the following calibration factors:

	Calibration Factors		
	2005	2004	2003
Kahe (LSFO)	1.017	1.0134	1.0061
Waiau Steam (LSFO)	1.008	1.0278	1.0211
Waiau CTs (Diesel Fuel)	1.275	1.2288	1.1231
Honolulu (LSFO)	0.943	0.9747	0.9540
HECO System	1.024	1.0275	1.0159

Q. What calibration factors is HELCO using in its test year 2006 rate case (Docket No. 05-0315)?

A. HELCO is using two calibration factors, one for each type of fuel it uses. HELCO is using a calibration factor of 1.018 for Industrial Fuel Oil and 1.051 for diesel fuel. (See the direct testimony of Ms. Lisa Giang, HELCO T-4, page 22.)

Q. Why did HELCO apply two calibration factors – one for each type of fuel – to derive its estimate of its 2006 test year fuel consumption?

A. As Ms. Giang explained in her direct testimony in Docket No. 05-0315, HELCO T-4, pages 39 to 43, HELCO initially used a single, system-wide calibration factor to make a preliminary determination of test year fuel consumption. The use of a single, system-wide calibration factor followed the practice established in MECO's 1997 test year rate case (Docket No. 96-0040). In that case, the Consumer Advocate introduced the single, system-wide calibration factor method. This method was subsequently applied in MECO's 1999 test year rate case (Docket No. 97-0346) and in HELCO's 2000 test year rate case (Docket No. 99-0207). In its preliminary calculation of test year fuel expense in its 2006 test year rate case (Docket No. 05-0315), HELCO used the single, system-wide calibration factor of 1.032, which covered the most recent calibration year (2005). However, as Ms. Giang explained in her direct testimony, HELCO did not use this factor in the final calculation of test year fuel expense. Instead, HELCO used two separate calibration factors, one for each type of fuel used. The two factors were derived using a more precise modeling technique than the technique used in HELCO's previous rate case (test year 2000). The new modeling technique improves the accuracy of the calibration. The use of two calibration factors, one for each fuel type, improves the "transparency" of the results, i.e., it is more apparent where the difference between modeled and actual results is occurring.

Q. What modeling technique did HELCO use in its previous 2000 test year rate case to determine the calibration factor?

A. In its previous rate case, HELCO used a probabilistic modeling technique to determine the calibration factor. In essence, in the probabilistic technique, forced outages for generating units are treated as deratings, instead of as random outages, in the model. For example, a 20 MW generating unit with a forced outage rate of 5% is treated as a 19 MW unit that is available whenever it is not on planned outage.

Q. What new modeling technique did HELCO apply for the purpose of determining the calibration factors in its 2006 test year rate case?

A. For the purpose of determining the calibration factors in its 2006 test year rate case, HELCO applied a Monte Carlo technique. In essence, in the Monte Carlo technique, forced outages for generating units are treated as random, discrete outages, in one week increments. For example, for a 20 MW generating unit with a 5% forced outage rate, the computer model will randomly take the unit out of service (during periods when it is available) up to a total forced outage time of

5%. In other words, the unit can operate at 20 MW for 95% of the time it is not on a planned outage, and will not be able to operate (i.e., will have a zero output) for 5% of the time it is not on a planned outage. The user of the computer program can specify the number of iterations that the program should perform this outage simulation. In each iteration, the computer program will take the generating unit out during a different period. The program will essentially take the average of the results of multiple iterations. A greater number of user-specified iterations will increase the time needed to run each simulation.

Q. Why did HELCO apply the Monte Carlo technique instead of the probabilistic technique for the purpose of determining the calibration factors in its test year 2006 rate case?

A. HELCO observed that using the probabilistic technique to simulate the calibration year resulted in an underestimation by the model of the run hours and generation from the peaking units (the 2.75 MW diesel engines) and certain combustion turbines. The reason this occurs is that the model assumes the generating units are available to operate (when they are not on a planned outage) at some given load that is determined by their normal top load rating and forced outage rate. In essence, on average, it is as if the units are never <u>fully</u> unavailable (except when they are on a planned outage), but are always available at a derated capacity (equal to their normal capacity less the forced outage rate). Therefore, the peaking units and combustion turbines are "called upon" by the model less frequently to operate to meet demand than they actually are.

On the other hand, with the Monte Carlo technique, generating units are randomly made fully unavailable within the model to reflect their forced outage rates. When large increments of capacity are made unavailable within the model, the peaking units and combustion turbines are modeled to operate more frequently and for longer hours to help make up for the output of the generating units that are periodically forced out of service and fully unavailable. This is a closer reflection of what actually occurs on the system. HELCO observed that by using the Monte Carlo technique, the model was better able to match actual operating hours and energy production from the peaking units and combustion turbines.

In HELCO's test year 2006 rate case, application of the Monte Carlo technique resulted in a reduction of the single, system-wide calibration factor from 1.032 to 1.026, meaning that there was a smaller difference between modeled and actual results in the calibration year and that the model was better able to simulate the actual operation of the system in the calibration year.

Q. Did HELCO then use this single, system-wide calibration factor of 1.026 to adjust the modeled fuel consumption its test year 2006 rate case?

A. No. Instead, HELCO determined two calibration factors – one for each type of fuel.

Q. Why did HELCO use two calibration factors in lieu of a single, system-wide calibration factor?

A. HELCO also observed that even with the Monte Carlo technique, there was a larger difference between actual and modeled run hours and energy generation for the units that use diesel fuel (i.e., the diesel engines and combustion turbines) compared to the difference between actual and modeled run hours and energy generation for the units that use industrial fuel oil ("IFO") (i.e., the steam units). The reason there is a smaller difference between actual and modeled run hours and energy generation for the steam units is that the three largest steam units (Hill 5, Hill 6 and Puna steam unit) are baseloaded, meaning that they run 24 hours a day at steady outputs, except at night when they must reduce their outputs because of the lower system demand. The diesel engines and combustion turbines, on the other hand, serve the peak hours (7 am to 9 pm) where there can be substantial variability in the load to be served by these units due to hourly changes in system demand, variability in the availability of firm IPP units, and variability in output of the as-available wind and run-of-river hydro units. The model can better replicate the operation of the steady-running steam units than the units with variable outputs, especially when the variable outputs are the result of the unpredictable outputs of the as-available units.

Q. What two calibration factors did HELCO derive for the two fuel types?

A. The two calibration factors that HELCO derived were 1.018 for IFO and 1.051 for diesel fuel. (See HELCO-WP-404, page 54.) HELCO used these two calibration factors to adjust the fuel consumption in the 2006 test year to arrive at the test year fuel expenses.

Q. Did HECO determine single, system-wide calibration factors using both the probabilistic and Monte Carlo techniques to compare the results?

A. Yes. HECO determined a single, system calibration factor of 1.031 using the probabilistic technique and a factor of 1.0199 using the Monte Carlo technique.

Q. What calibration factor is HECO using in the instant docket?

A. HECO is using the calibration factors, broken down by plant and fuel type as shown earlier in my testimony. These calibration factors were determined using the Monte Carlo modeling technique, consistent with the technique used for the HELCO test year 2006 rate case.

Q. Why is HECO using calibration factors broken down by plant as well as fuel type?

A. Breaking down the calibration factor by power plant as well as fuel type allows a measure of "fine-tuning" of the calibration.

Derivation of Fuel Expense

Q. Once fuel consumption is determined, and fuel price assumptions are made, how is fuel expense derived?

A. Once fuel consumption is determined, fuel expense is derived by applying the fuel prices discussed earlier in my testimony to the amount of fuel consumed. The derivation of the fuel expense is shown in HECO-404.

Q. What is HECO's estimate of fuel expense, excluding fuel related expenses, in the test year?

A. HECO's estimate of fuel expense, excluding fuel related expenses, in the test year is $536,833,000 (HECO-404).

FUEL-RELATED EXPENSE

Q. What is the total fuel-related expense for the 2007 test year?

A. Estimated 2007 fuel-related expenses are $6,128,000, as shown on HECO-405.

Q. What costs are included in the test year forecast of fuel-related expenses?

A. Fuel-related expenses include the following:

1) Fuel Handling Expenses: Pipeline Facilities expense,
2) Fuel Handling Expense: Pipeline Maintenance expense,
3) Fuel Handling Expense: Tank Farm Management Fee,
4) Fuel Handling Expense: HECO Fuel Handling expenses,
5) Fuel Trucking expense,
6) Petroleum inspection (Petrospect) expense on fuel purchases, and
7) Kahe 6 Fuel Additive expense.

An explanation of each of these items is provided later in my testimony.

Q. What was the basis for the estimates for fuel-related expenses?

A. The fuel-related expenses are based primarily on the operations and maintenance of HECO's fuel facilities includes the HECO Barbers Point Tank Farm (BPTF) which receives all Low Sulfur Fuel Oil (LSFO) deliveries from suppliers Chevron Products Company (Chevron) and Tesoro Hawaii Corporation (Tesoro). Prior to the installation of pumps, piping, valves and related facilities that formed a portion of the installation of the Waiau Fuel Pipeline project, Docket No. 01-0444; LSFO shipments to HECO's Kahe and Waiau generating stations and HECO's Iwilei Tank Farm could and often did originate from storage tanks in the Chevron refinery. HECO's fuel facilities also includes HECO Kahe pipeline which is utilized to distribute fuel from BPTF to HECO's Kahe generating station and the HECO Waiau pipeline (which went into service December 2004, previously shipments were made via the multi-user and multi-product Chevron Black Oil pipeline) which is utilized to distribute LSFO from BPTF to HECO's Waiau generating station. HECO distributes LSFO from BPTF to HECO's Iwilei Tank Farm via trucks loaded via a truck loading system installed at BPTF as part of the referenced Waiau Fuel Pipeline Project (the service commenced January 2005, previously shipments were made via the multi-user and multi-product Chevron Black Oil pipeline). The fuel is delivered from the trucks via a truck unloading facility installed at the Iwilei Tank Farm (ITF) as part of the referenced Waiau Fuel Pipeline Project. From the ITF, fuel is delivered to the Honolulu Power Plant through an existing HECO 6-inch fuel pipeline. As a part of the Waiau Pipeline Project, a diesel tank and diesel truck unloading facility was installed in BPTF. The primary purpose of the diesel stored at BPTF is for the emergency displacement of the Kahe and/or Waiau pipelines in the case of an emergency to prevent the heated LSFO from cooling and then solidifying inside the pipelines.

Q. When was the Waiau Fuel Pipeline placed into service?

A. The Waiau Fuel Pipeline and related pipeline facilities were placed into commercial operation on December 6, 2004.

Q. Please describe how HECO's fuel facilities will be operated and maintained in the test year.

A. Operation and maintenance of HECO's fuel facilities will be as follows:

<u>Barbers Point Tank Farm</u>

Chevron was contracted under the terms of the "Operations and Maintenance Agreement," dated December 14, 2004, to provide LSFO delivery coordination into HECO's BPTF, operations and maintenance of BPTF and the Waiau and Kahe pipelines, operating and maintaining the pipeline leak detection system, gauging and sampling tanks outside of custody transfer transactions, fuel inventory and movement accounting and reporting services, preparation and maintenance of all documents, records and procedures required by the U.S. Department Of Transportation, conduct pipeline right-of-way inspections and maintenance as required by federal regulations, laboratory and security services. Chevron was also contracted under the terms of the "Barbers Point Tank Farm Services Agreement," dated December 14, 2004, to provide low pressure steam to BPTF tank heaters and steam tracing and to provide fire protection water and incipient fire protection services. These two contracts are the successor agreements to the "Facilities and Operations Contract" between Chevron and HECO under which provisions HECO used certain Chevron refinery support infrastructure, facilities and the Chevron Black Oil pipeline and under which Chevron provided operations and maintenance services of HECO's BPTF and Kahe pipeline. HECO's Fuels Division will continue to provide contracting oversight over Chevron's operating and maintenance efforts.

<u>HECO's Kahe Pipeline</u>

There are no planned changes to the Kahe pipeline operations as Kahe will continue to primarily utilize high pour point/high viscosity LSFO (to the extent product quality segregation can be practically maintained at BPTF) and the pipeline operate in the continuous flow mode.

<u>HECO's Waiau Fuel Pipeline</u>

There are no planned changes to the Waiau pipeline operations as Waiau will continue to primarily utilize low pour point/low viscosity LSFO (to the extent product quality segregation can be practically maintained at BPTF) and operate in the continuous flow mode.

<u>Delivery to HECO's Iwilei Tank Farm</u>

Truck loading facilities at BPTF allow for the loading of approximately 135 barrels of low pour point/low viscosity LSFO (to the extent product quality segregation can be practically maintained at BPTF) into trailer mounted cradled container tanks. These tanks are filled by the truck driver with site and loading system accessed through an automated security system which generates product loading documents and is monitored by Chevron refinery personnel. Driver and equipment is provided by Bering Sea Eccotech, Inc. (BSE) under the terms of a trucking freight contact dated November 24, 2004 which transports the LSFO to the ITF. At the ITF, site access and discharging system is accessed by the BSE truck driver through an automated system. The trucker connects the discharge hose and other equipment through which the LSFO is delivered into the Iwilei LSFO piping and into a storage tank. The day-to-day operations and oversight of the ITF will continue to fall under the Honolulu Plant Operations.

Facilities Base Expense

Q. What is HECO's cost estimate of the Facilities Base Expense in the test year?

A. HECO's cost estimate of the Pipeline Facilities Base Expense in the test year is $2,140,000.

Q. Please explain the basis for this cost estimate.

A. For the HECO Kahe Pipeline, the $613,000 is a prorata share of the projected 2007 "Base Fee" charged monthly for pipeline operations and maintenance under the provisions of the "Operations and Maintenance Agreement," dated December 14, 2004, referenced above. The Base Fee consists of a fixed portion, $48,986 per month, and a portion subject to escalation. The escalated amount as of the commencement of the agreement, $114,302 per month, is subject to quarterly escalation thereafter on the basis of the increase in a quarterly average of hourly earnings for petroleum and coal products industry as published by the U.S. Bureau of Labor Statistics. The escalated portion of the actual 2005 charges escalated via a U.S. DOE/EIA forecast for the GDP Implicit Price Deflator value for 2007 and to which the fixed portion of the Base Fee was added. The proration was made on the basis of the length of the Kahe Pipeline, 5.144 miles, against the total length of the two pipelines operated and maintained by Chevron (5.144 miles + 12.804 miles = 17.948 miles).

For the HECO Waiau Pipeline, the $1,527,000 is a prorata Base Fee applicable to the Waiau Pipeline was made on the basis of the length of the Waiau Pipeline, 12.804 miles, against the total length of the two pipelines operated and maintained by Chevron (5.144 miles + 12.804 miles = 17.948 miles).

Q. What is HECO's cost estimate of the Pipeline Maintenance Expense in the test year?

A. HECO's cost estimate of the Pipeline Maintenance Expense in the test year is $435,000.

Q. Please explain the basis for this cost estimate.

A. For the HECO Kahe Pipeline, the $302,000 estimate is based upon the average of the HECO Kahe pipeline "Maintenance Charge" actually incurred for each of the years 2003 and 2004 and "Facilities Non-Base Maintenance" for 2005 incurred under the terms and conditions of the then existing contractual agreement between Chevron and HECO, the "Facilities and Operations Contract" and "Operations and Maintenance Agreement," respectively, adjusted to 2007 dollars. The scope of the reimbursable or "Non-Base" maintenance performed under the "Facilities and Operations Contract" and its successor agreements are fundamentally the same. Therefore, the historical costs serve as a reasonable basis for estimates of test year costs.

For the HECO Waiau Pipeline, which only entered service in December 2004, starting in late 2004, the $133,000 estimate is based upon the HECO Waiau "Facilities Non-Base Maintenance" actually incurred for 2005 under the terms and conditions of the "Operations and Maintenance Agreement," adjusted to 2007 dollars. The historical costs serve as a reasonable basis for estimates of test year costs.

Tank Farm Management Fee

Q. What is HECO's cost estimate of the Tank Farm Management Fee in the test year?

A. HECO's cost estimate of the Tank Farm Management Fee in the test year is $1,133,000.

Q. Please explain the basis for this cost estimate.

A. The estimated cost of $1.113 million for the operations, maintenance and provision of services for HECO's BPTF is comprised of five components. The first of these is the "Base Fee" of $24,375 per month charged under the terms of the "Barbers Point Tank Farm Services Agreement," dated December 14, 2004. The Base Fee consists of a fixed portion, $23,186 per month, and a portion subject to escalation. The escalated amount as of the commencement of the agreement, $1,219 per month, is subject to quarterly escalation thereafter on the basis of the increase in a quarterly average of hourly earnings for petroleum and coal products industry as published by the U.S. Bureau of Labor Statistics. The escalated portion of the actual 2005 charges escalated via a U.S. DOE/EIA forecast for the GDP Implicit Price Deflator value for 2007 and to which the fixed portion of the Base Fee was added. The second component of the Tank Farm Services expense is the cost estimate for the supply of low pressure steam to the storage tank and piping heat tracing systems. The estimated steam expense is based upon the average of the cost of steam actually incurred for each of the years 2003 and 2004 under the "Facilities and Operations Contract" and incurred in 2005 under the terms of the "Barbers Point Tank Farm Services Agreement," adjusted to 2007 dollars. The basis of the contractual charge for steam in terms of dollars per 1,000 lbs under the two agreements is the same. Therefore, the historical costs serve as a reasonable basis for estimates of test year steam cost. The third component of Tank Farm Services expense is based upon the average of the HECO BPTF "Maintenance Charge" actually incurred for each of the years 2003 and 2004 and "Facilities Non-Base Maintenance" for 2005 incurred under the terms and conditions of the then existing contractual agreement between Chevron and HECO, the "Facilities and Operations Contract" and "Operations and

Maintenance Agreement," respectively, adjusted to 2007 dollars. The scope of the reimbursable or "Non-Base" maintenance performed under the "Facilities and Operations Contract" and its successor agreements are fundamentally the same. Therefore, the historical costs serve as a reasonable basis for estimates of test year costs. Unlike the case for pipelines, for which in-line inspection and major maintenance, such as pipeline section replacement, occurs every 2 to 3 years (thus the 3-year normalization period used to average historical pipeline and related costs), periodic major maintenance activity in BPTF consists largely of such activities as tank cleaning, bottom thickness inspection and measurement, bottom plate repair, bottom/lower side wall epoxy coating and other related maintenance and repair to the three fuel storage tanks in the facility occur on a very long cycle – currently forecast as 12 years. The three LSFO storage tanks in BPTF last went through the cleaning, inspection, maintenance and repair processes in 1995, 1996 and 1997, respectively, were scheduled to again go through this maintenance cycle in 2006, 2007 and 2008, respectively – each tank taking from 9 to 12 months to complete cleaning, inspection, maintenance and repair. However, in 2006 the inspection of the side shell of Tank # 131 requiring the removal of portions of its external covering heat-containment insulation revealed the unexpected presence of significant surface corrosion and pitting. An analysis by a Chevron Inspector Analysts API 653 pertaining to tank condition is currently ongoing as is the participation of a petroleum tank consultant, Matrix Services, to recommend an appropriate repair strategy. This has delayed taking the tank out of service, this is now anticipated to occur in mid-March 2007, with the expected out of service period of Tank # 132 and Tank # 133 delayed by 1 year accordingly – to 2008 and 2009, respectively. Nevertheless, the tank maintenance and repair cost included in the Tank Farm Services expense is the normalized (1/12) average of the actual annual amounts of such major maintenances incurred in the years 1995 through 1997, adjusted to 2007 dollars.

HECO Fuel Handling Expense

Q. What is HECO's cost estimate of the internal fuel handling expense in the test year?

A. HECO's cost estimate of the internal fuel handling expense in the test year is $1,130,793.

Q. Please explain the basis for this cost estimate.

A. The estimated cost of $1.131 million for fuel handling operations within HECO are comprised of three components. The first of these are non-labor charges by the HECO Information Technology & Services Department for software licenses, hardware and other non-labor charges incurred for the maintenance of the Fuel Management and Reporting System (FMRS) which converts and reports tank reading data including liquid height gauges, product temperature and product density into temperature corrected volumetric data on tank and plant inventory volumes, pipeline shipment received volumes and plant consumption volumes. It combines inputted data on the heat content of LSFO and diesel purchased and shipped with inputted data on unit watt-hour meter readings to compute and report plant gross, auxiliary and net generation in KWh, system Btu consumption and related heat rate values. The second component is HECO Fuels Division labor, non-labor and overheads which includes the labor of the Director of Fuels Resources, Fuels Contract Administrator, Forecast Planning Analyst and other Fuels Division personnel not charged to tasks performed for HELCO and MECO (reflecting actual historical apportionment in 2003, 2004 and 2005) or to specific non-Fuels Division activities, related overhead expenses and general and administrative expenses similarly not incurred due to fuel procurement, logistics planning, fuel-related contract administration and other tasks performed for the specific benefit of HELCO and MECO. The largest non-labor cost incurred by the Fuels Division would be petroleum inspection expense incurred for the gauging of intra-facility pipeline shipments and monthly and plant storage tanks on a periodic basis – prior to 2005 the cost of petroleum inspection fees on intra-facility shipments was recovered via the Energy Cost Adjustment mechanism because the fees were incurred to determine the volume of such shipments upon which per unit through charges were levied by Chevron under the terms of the referenced "Facilities and Operations Contract." The amount of petroleum inspection expense included in the Fuels Division non-labor expense in the test year was based upon the actual historical expense incurred for the most recent period for which data was available, the 10 months from May 2005 through February 2006, adjusted to 2007 dollars. The third component of HECO Fuel Handling Expense is labor and non-labor expense of HECO Operations & Maintenance personnel such as Utility Operators and Shift Supervisors who perform tasks related to the receipt of pipeline shipments at the Kahe, Waiau and Honolulu generating stations such as coordinating shipment receiving tank piping and valve line ups with Chevron control operators, measuring and recording liquid heights in tanks, measuring and recording product temperatures in storage tanks, mixing post-receipt tank contents and taking samples of tank contents for delivery to the HECO Chem. Lab. This labor and overhead expense was based upon the actual labor hours of HECO personnel charged to such activities during 2004 and 2005. The historical activity level is considered as a reasonable basis for estimates of test year costs. The total HECO Fuel Handling Expense is applied on a prorata dollar amount basis to each of the components of the Fuel Handling Expense which is consistent with previous test year expense computation methodology.

Fuel Trucking Expense

Q. What is HECO's cost estimate of the Fuel Trucking Expense in the test year?

A. HECO's cost estimate of the Fuel Trucking Expense in the test year is $1,092,000.

Q. Please explain the basis for this cost estimate.

A. The estimate is based upon trucking LSFO from BPTF to HECO's ITF and upon trucking diesel from Chevron's Honolulu Distribution Terminal to various Distributed Generation (DG) sites. As previously noted, LSFO is transported by truck to ITF under the terms of a trucking freight contract between HECO and Bering Sea Eccotech, Inc. (BSE) dated November 24, 2004. The base period freight rate excluding taxes was $2.925 per barrel (BSE received PUC Hawaii tariff approval, see Local Specialized Freight Tariff 14, Section 4, Part D, Item 6405, issued January 21, 2005 and effective January 28, 2005). The freight rate used for the cost estimate is the rate currently in effect as of August 2006 under the contract, $2.969 per barrel and a tax rate of 4.4386%, reflecting application of HGET and Motor Carrier Gross Revenue Fee for a total per unit freight cost of $3.101 per barrel which was applied to the forecast consumption of the Honolulu Power Plant. Fuel consumed by the DG units at the various sites is purchased under the terms of an already existing contract between Chevron and HECO which provides for the purchase of diesel at the truck loading facility of Chevron's Honolulu Distribution Terminal (HDT) in Iwilei. This diesel is transported from HDT to the various DG sites including ITF, HECO's Ewa Nui substation, HECO's Halemano substation and locations to be added in 2007, including HECO's Campbell Industrial Substation and the HECO "Pole Yard" (adjacent to the IPP, Kalaeloa Partners Limited Partnership generating facility, located within the Campbell Estate Industrial Park) under the terms of a contract between HECO and D&K Petroleum, Inc. (dba D&K Trucking) a local Oahu petroleum wholesaler. The freight rates per unit transported to be charged under this contract are the PUC approved published tariff rates then in effect plus applicable taxes, HGET and Motor Carrier Gross Revenue Fee. The trucking freight rates for truck shipments originating in Iwilei are applied to the forecast annual consumption of the DG units to derive a test year expense estimate.

<u>Petroleum Inspection (Petrospect) Expense</u>

Q. What is HECO's cost estimate of the Petroleum Inspection (Petrospect) Expense that is being passed through the ECAC in the test year?

A. HECO's cost estimate of the Petroleum Inspection (Petrospect) Expense in the test year is $84,000.

Q. Please explain the basis for this cost estimate.

A. The use of an independent third-party petroleum inspection service to measure the change in storage tank heights and product temperature for the determination of the volume of LSFO and diesel purchased in bulk by HECO from Chevron and Tesoro is a long-term requirement and stipulated provision of the terms of HECO's fuel supply contacts with each of the respective parties, as approved by the Hawaii Public Utilities Commission. In each of these cases, the selection of the particular petroleum inspection service vendor is a joint decision between HECO and Tesoro or Chevron, respectively, and the charge of the petroleum inspector is accordingly shared on an equal basis between the companies. The estimated expense for petroleum inspection services performed by Petrospect, Inc. under the terms of a contract between Petrospect and HECO dated July 8, 2005, is based upon the actual petroleum inspection charges incurred in relation to actual fuel purchases from Chevron and Tesoro made from January 1, 2006 to June 30, 2006. A "costing" rate was computed on the basis of the petroleum inspections fees actually incurred and the volume of fuel purchased from each supplier and these costing rates where then applied to the fuel consumption volumes forecast for the test year, adjusted to 2007 dollars.

<u>Kahe 6 Fuel Additive Expense</u>

Q. What is HECO's cost estimate of the Kahe 6 Fuel Additive Expense that is being passed through the ECAC in the test year?

A. HECO's cost estimate of the Kahe 6 Fuel Additive Expense in the test year is $113,000.

Q. Please explain the basis for this cost estimate.

A. The estimated test year expense of using of Calcium Nitrate Additive to control air emissions consistent with the regulatory and permitting requirements pertaining to the operation of generating unit Kahe 6 is based upon its forecast generation expressed in gallons of LSFO equivalent (715,694 MWh equates to 7,475,899 MBtu, which in turn equates to 50,643,187 gallons). Based upon actual field testing conducted in 2006 and technical research, the fuel additive dosage is estimated at 1 gallon of additive per 4,000 gallons of LSFO consumed – which equates in the test year to 12,661 gallons of additive usage. The estimated cost of the additive fob plant, estimated shipping and handling through the Company's stores/warehouse and application of related taxes results in a per gallon additive cost estimated cost at approximately $8.897 per gallon.

HECO GENERATION EFFICIENCY

Q. What is the test year net generation heat rate for HECO?

A. The test year net heat rate for HECO Central Station units is 10,691 Btu/kWh. The heat rate is shown in HECO-406, line 13.

Q. What is a "net heat rate"?

A. The net heat rate is a measure of generation efficiency. It is the heat content of the fuel consumed (in Btus) per net kWh generated. That is, for HECO in the test year, an estimated 10,691 Btus of fuel heat are required for the HECO units, on average, to produce one kWh of energy.

Q. How does the test year net heat rate compare to historical performance?

A. As shown in HECO-407, lines 5 and 6, the estimated base case test year net system heat rate is 0.0 percent, or 1 Btu/kWh, higher than actual 2005.

Q. Why would the heat rate return to 2005 levels?

A. The heat rate will return to 2005 levels for the following reason: The higher heat rate in 2005 (compared to 2006) was attributed to more HECO reheat unit/IPP outages and greater instances of stacked outages. This reduced the contribution of more, efficient reheat unit generation and increased the operation of less efficient steam cycling and combustion turbine units. For 2007, we forecast to return to almost the same level of HECO/IPP maintenance as in 2005, and therefore, we expect our forecasted heat rates to closely resemble 2005 (which would be an increase from 2006).

Q. How does the test year net heat rate affect ratemaking in this proceeding?

A. The net heat rate directly affects the "sales heat rate". The sales heat rate is calculated in a similar manner as the net heat rate, except the sales heat rate is the heat content of the fuel consumed per kWh of sales. The sales heat rate in the form of a Generation Efficiency Factor is used in the Energy Cost Adjustment Clause to translate the base generation cost in cents per MBtu to the weighted base generation cost in cents per kWh of sales.

For HECO, the sales heat rate is computed by dividing the test year fuel consumption (in MBtus) by the proportion of sales provided by HECO generation (in kilowatt-hours). The resulting base case Generation Efficiency Factor is 0.011226 MBtu/kWh. (See HECO-406, line 18.) The Energy Cost Adjustment Clause is discussed by Mr. Hee in HECO T-9.

FUEL INVENTORY

Q. What is the test year estimate of fuel inventory?

A. The estimated base case fuel inventory is $52,706,000. This is based on fuel inventories of 770,024 bbls of LSFO, with a value of $50,224,000, and 24,873 bbls of diesel fuel valued at $2,482,000. (See HECO-408.)

LSFO Inventory

Q. How was the amount and value of LSFO inventory determined?

A. The LSFO inventory amount and value were determined from a 35-day inventory. HECO had proposed a 35-day LSFO inventory amount in its previous rate case (test year 2005, Docket No. 04-0113) based on a conclusion of its December 2003 Fuel Inventory Study.

Q. Did the Commission accept this 35-day inventory amount for inclusion in its rate base?

A. Yes. The Settlement Letter executed by HECO, the Consumer Advocate and the DOD in Docket No. 04-0113 stated the following in paragraph 16.c. (Fuel Inventory):

There are no differences with respect to the methodology used to calculate LSFO and diesel fuel inventory. For purposes of settlement, the Consumer Advocate and the DOD have accepted HECO's estimated test year fuel amounts and fuel prices. For purposes of settlement, the Consumer Advocate and the DOD also accept HECO's estimated fuel inventory amounts, including HECO's revised diesel fuel inventory based on updated 5-year data.

Interim Decision and Order No. 22050 effectively accepted the inventory amount as it stated on page 7, "Where the Parties agree, we accepted such agreement for purposes of this Interim Decision and Order."

Q. How was the 35 day value used to determine the total LSFO inventory volume and value?

A. The 35 day value was multiplied by the average daily fuel consumption rate to arrive at the total inventory volume in barrels. (See HECO-409 page 1, line 3.) This total inventory volume was multiplied by the price of the fuel to arrive at the total inventory value in dollars. (See HECO-409 page 1, line 5.)

Q. How is the average daily fuel consumption rate determined?

A. The average daily LSFO consumption for HECO is derived from the estimated test year fuel consumption and divided by 365 days in the year. (See HECO-409, page 2.)

Q. What is the impact on daily fuel consumption of purchased energy from Kalaeloa and AES?

A. As discussed earlier, under the topic of fuel expense, HECO units produce the energy required above purchased power to meet the needs of the Company's customers. Therefore, the increase in purchased energy from Kalaeloa and AES during the normalized test year decreases the amount of energy that HECO's generating units need to produce. This also reduces the amount of fuel burned and results in lower daily fuel consumption.

Q. What has been the historical level of LSFO inventory?

A. Over the past five years, LSFO inventory has been approximately 38 days, as shown in HECO-410.

Diesel Fuel Inventory

Q. How was the amount and value of diesel fuel inventory determined?

A. The amount of diesel fuel inventory was based on a five-year average (2001-2005).

Q. Why was a five-year average inventory used for diesel fuel?

A. This was based on the methodology used in HECO's previous rate case (Test Year 2005 in Docket No. 04-0113). Also, in HECO's test year 1995 rate case (Docket No. 7766), the Commission approved the inclusion of 31,123 barrels of diesel fuel, based on a five-year average.

Q. What has been HECO's average historical diesel fuel inventory?

A. HECO's historical diesel fuel inventory levels from 2001 to 2005 are shown in HECO-411. The average inventory level over this five-year period was 23,416 bbls.

Q. How was the value of this inventory amount determined?

A. The total inventory volume was multiplied by the price of the diesel fuel to arrive at the total inventory value in dollars. (See HECO-408, page 1, line 2.)

Q. Does the diesel fuel inventory include an amount of inventory for the DG units at HECO sites that are discussed in the testimony of Mr. Giovanni in HECO T-6?

A. Yes, 1,457 barrels of diesel fuel inventory are included for the DG units (HECO-411).

Q. How does the total fuel inventory compare to historical levels?

A. The test year LSFO inventory of 770,024 bbls is lower than the five-year average LSFO inventory (see HECO-410.) The test year diesel fuel inventory of 24,873 bbls is based on historical levels.

SUMMARY

Q. Please summarize your testimony.

A. The testimony presented supports the reasonableness of the following values for the 2007 test year:

			Units
1)	Fuel Expense	542,961,000	$
	a) Fuel Expense (Oil)	536,833,000	$
	b) Fuel-Related Expense	6,128,000	$
2)	Fuel Price		See HECO-402
3)	Purchased Energy Forecast	3,372.7	GWH
4)	Efficiency Factor (Sales Heat Rate)	0.011226	MMBTU/KWH SALES
5)	Fuel Inventory	52,706,000	$

The above items were determined by detailed analyses and methodologies, are consistent with historical values considering known and expected conditions, and are consistent with all items in this case as they relate to each other.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

Ross H. Sakuda, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI
Position:	Director, Generation Planning Power Supply Services Department
Education:	Bachelor of Science in Mechanical Engineering University of Hawaii, 1978
Other Qualifications:	Registered Professional Engineer Hawaii Mechanical Branch - 1983
Experience:	HAWAIIAN ELECTRIC COMPANY, INC. April 2000 to Present Director, Generation Planning Power Supply Services Department (Power Supply Planning & Engineering Department prior to September 20, 2004)
	November 1999 - March 2000 Project Manager Power Supply Planning & Engineering Department
	August 1995 - October 1999 Senior Planning Engineer Power Supply Planning & Engineering Department
	1993 - July 1995 Senior Mechanical Engineer Power Supply Planning & Engineering Department

Experience (cont'd):	1990 - 1992 Project Manager Engineering Department
	October 1983 - 1989 Mechanical Engineer Engineering Department
	November 1979 - September 1983 Mechanical Designer Engineering Department
	<u>NAKASHIMA ASSOCIATES</u> April 1979 - October 1979 Mechanical Designer
Other Curriculum:	Corporate Training Course Zenger-Miller Supervision Course Utility Finance and Accounting Course
Previous Testimony:	Hawaiian Electric Company, Inc. Campbell Industrial Park Generation Station and Transmission Additions Project Docket No. 05-0145
	HECO/HELCO/MECO PUC Proceeding to Investigate Competitive Bidding for New Generation in Hawaii Docket No. 03-0372
	Hawaiian Electric Company, Inc. Request for Approval of Rate Increase Test Year 2005 Docket No. 04-0113
	HECO/HELCO/MECO PUC Proceeding to Investigate Distributed Generation Docket No. 03-0371
	Hawaii Electric Light Company, Inc. Apollo Energy Corporation Petition Docket No. 00-0135

Previous Testimony (cont'd): Hawaii Electric Light Company, Inc.
Request for Approval of Rate Increase
Test Year 2000
Docket No. 99-0207

Hawaiian Electric Company, Inc.
Waiau Water Agreements
Docket No. 7277

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EXPENSES

Line	Fuel Type	Reference	TY 2007 Fuel Expense ($000)
1.	**Total Fuel Oil Expense**	HECO-401, p. 2, Line 4	$536,833
2.	**Total Fuel Related Expense**	HECO-405, p. 1, Line 5	$6,128
3.	**TOTAL FUEL EXPENSE**		$542,961

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EXPENSES
TOTAL FUEL OIL EXPENES

Line	Fuel Type	Reference	TY 2007 Fuel Oil Expense ($000)
1.	Low Sulfur Fuel Oil	HECO-404, p. 1, Line 4	$522,779
2.	Diesel Fuel Oil	HECO-404, p. 1, Line 6	$10,065
3.	Sub. DG Diesel Fuel Oil	HECO-404, p. 1, Line 8	$3,989
4.	TOTAL FUEL OIL EXPENSE		$536,833

Note: Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

FUEL PRICES FOR 2007 TEST YEAR
WEIGHTED AVERAGE FUEL PRICES

This exhibit contains confidential pricing information and has been deleted from this copy. Page 1 of 1 with the deleted information will be filed pursuant to an appropriate protective order.

Hawaiian Electric Company, Inc.

2007 TEST YEAR GENERATION

Line		(A) Energy (GWh)	(B) Percent of Net System Input
1.	Sales	7,720.8	
2.	Company Use[1]	15.4	
3.	Sales + NC	7,736.2	
4.	Losses[2]	373.0	
5.	Net System Input	8,109.2	100.00%
6.	- Purchase Power[3]	3,372.7	41.59%
7.	Net HECO	4,736.5	58.41%
7a.	Central Station	4,713.5	58.12%
7b.	Substation DG[4]	23.0	0.28%

[1] No Charge based on 2001-2005 5 year average, 15.4 MWh. (HECO-WP-403, p. 1)
[2] Losses of 4.60% based on 5-year average (2001-2005), HECO-WP-403, p. 2
[3] HECO-409, page 6.
[4] Includes DSG, HECO-409, p. 6

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Contract Fuel Prices)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Contract Prices ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	295,205	65.1012	$ 19,218
2.	Kahe	5,685,644	65.1012	$ 370,142
3.	Waiau-Steam	2,049,397	65.1012	$ 133,418
4.	Subtotal	8,030,246		$ 522,779
5.	Waiau-Diesel	101,195	99.4609	$ 10,065
6.	Subtotal	101,195		$ 10,065
7.	Central Station Total	8,131,441		$ 532,843
8.	Substation DG	40,109	99.4609	$ 3,989
9.	Grand Total	8,171,550		$ 536,833

Composite Fuel Price **65.6953** **$/bbl**

[1] HECO-402, Line 5.

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Including Trucking and Petrospect Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Fuel Costs ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	295,205	68.2113	$ 20,136
2.	Kahe	5,685,644	65.1103	$ 370,194
3.	Waiau-Steam	2,049,397	65.1103	$ 133,437
4.	Subtotal	8,030,246		$ 523,768
5.	Waiau-Diesel	101,195	99.5339	$ 10,072
6.	Subtotal	101,195		$ 10,072
7.	Central Station Total	8,131,441		$ 533,840
8.	Substation DG	40,109	103.9439	$ 4,169
9.	Grand Total	8,171,550		$ 538,009
		Composite Fuel Price		65.8393 $/bbl

[1] HECO-402, Line 9.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL RELATED EXPENSES

Line		Dollars ($000)	Reference
1.	Fuel Handling Expenses	$ 4,839	HECO-WP-410
2.	Fuel Trucking Expenses	$ 1,092	HECO-405, page 2
3.	Petrospect Expenses	$ 84	HECO-405, page 3
4.	Kahe 6 Fuel Additive Expense	$ 113	HECO-WP-411
5.	Total	$ 6,128	

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Trucking Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Trucking Cost ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	295,205	3.1010	$ 915
2.	Kahe	5,685,644	-	$ -
3.	Waiau-Steam	2,049,397	-	$ -
4.	Subtotal	8,030,246		$ 915
5.	Waiau-Diesel	101,195	-	$ -
6.	Subtotal	101,195		$ -
7.	Central Station Total	8,131,441		$ 915
8.	Substation DG	40,109	4.4100	$ 177
9.	Grand Total	8,171,550		$ 1,092

[1] HECO-402, Line 6.

Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Petrospect Costs)

Line	LSFO	(A) Fuel Consumption (Barrels)	(B)[1] Petrospect Cost ($/bbl)	(C) = (A) x (B) (C) Fuel Expense ($000)
1.	Honolulu	295,205	0.0092	$ 3
2.	Kahe	5,685,644	0.0092	$ 52
3.	Waiau-Steam	2,049,397	0.0092	$ 19
4.	Subtotal	8,030,246		$ 74
5.	Waiau-Diesel	101,195	0.0730	$ 7
6.	Subtotal	101,195		$ 7
7.	Central Station Total	8,131,441		$ 81
8.	Substation DG	40,109	0.0730	$ 3
9.	Grand Total	8,171,550		$ 84

[1] HECO-402, Line 8.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL EFFICIENCY

Line			
	ENERGY		
1.	**Company Generated Energy**	4,735.3	Net GWh
2.	**Central Station Generated Energy**	4,712.3	Net GWh
3.	**Steam Generated Energy**	4,693.2	Net GWh
4.	**CT Generated Energy**	19.1	Net GWh
5.	**Sub. DG Generated Energy**	23.0	Net GWh
6.	**Test Year Sales**	7,720.8	Net GWh
	FUEL CONSUMPTION		
7.	**Total Fuel Consumed**	50,615,565	MBtu
8.	**Central Station Fuel Consumed**	50,380,528	MBtu
9.	**Steam Fuel Consumed**	49,787,524	MBtu
10.	**CT Fuel Consumed**	593,004	MBtu
11.	**Sub. DG Fuel Consumed**	235,037	MBtu
	HEAT RATE		
12.	**Total Heat Rate**	10,689	Btu/kWh
13.	**Central Station Heat Rate**	10,691	Btu/kWh
14.	**Steam Heat Rate**	10,609	Btu/kWh
15.	**CT Heat Rate**	31,015	Btu/kWh
16.	**Sub. DG Heat Rate**	10,212	Btu/kWh
17.	**HECO Central Station Generation of Net System Input**	58.12%	Percent
18.	**Sales Heat Rate - Central Station**	0.011226	MBtu/kWh Sales[1]

Reference
[1] 50,380,528 MBtu / (7,720.8 GWh x 58.12% x 1,000,000 kWh/GWh) = 0.011226 MBtu/kWh Sales.

Source: HECO-409, page 2 and 6 and HECO-407.

Hawaiian Electric Company, Inc.

HISTORICAL FUEL EFFICIENCY
(Btu/Net kWh)

Line		(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) Test Year 2007
1.	**Central Station Steam**	10,387	10,414	10,413	10,540	10,620	10,609 [1]
2.	**Percent Increase**		0.3%	0.0%	1.2%	0.8%	-0.1%
3.	**Central Station Diesel**	29,053	21,106	21,081	21,327	20,985	31,015 [2]
4.	**Percent Increase**		-27.4%	-0.1%	1.2%	-1.6%	47.8%
5.	**Central Station Average**	10,406	10,436	10,452	10,621	10,690	10,691 [3]
6.	**Percent Increase**		0.3%	0.2%	1.6%	0.7%	0.0%
7.	**Substation DG**					10,081	10,212 [4]
8.	**Percent Increase**						1.3%

[1] HECO-406, Line 14.
[2] HECO-406, Line 15.
[3] HECO-406, Line 13.
[4] HECO-406, Line 16.

Hawaiian Electric Company, Inc.

TEST YEAR FUEL OIL INVENTORY

Line	LSFO	(A) Average Barrels[1]	(B) Price per Barrel	(C) = (A) x (B) (C) Fuel Oil Inventory ($000)
1.	**Residual Fuel Oil**	770,024	65.2243	$ 50,224
2.	**Diesel Oil**	24,873	99.7922	$ 2,482
3.	**TOTAL INVENTORY**	794,897		$ 52,706

Line		
4.	**AVERAGE RESIDUAL FUEL OIL PRICE**	
5.	**Residual Fuel Oil Expense (HECO-404, p. 2, Line 4, Column C)**	$ 523,768
6.	**Barrels of Residual Fuel Oil (HECO-404, p. 2, Line 4, Column A)**	8,030,246
7.	**Average Price per Barrel (Line 5 ÷ Line 6)**	$ 65.2243
8.	**AVERAGE DIESEL OIL PRICE**	
9.	**Central Station Diesel Oil Inventory Volume (HECO-411, Line 6)**	23,416
10.	**Substation DG Diesel Oil Inventory Volume (HECO-411, Line 7)**	1,457
11.	**Total Diesel Oil Inventory Volume (Line 9 + Line 10)**	24,873
12.	**Central Station Diesel Oil Price (HECO-404, Page 2, Line 5, Column B)**	$ 99.5339
13.	**Substation DG Diesel Oil Price (HECO-404, Page 2, Line 8, Column B)**	$ 103.9439
14.	**Central Station Diesel Oil Inventory Value (Line 9 * Line 12)**	$ 2,330,715
15.	**Substation DG Diesel Oil Inventory Value (Line 10 * Line 13)**	$ 151,446
16.	**Total Diesel Oil Inventory Value (Line 14 + Line 15)**	$ 2,482,161
17.	**Average Diesel Oil Price (Line 16 ÷ Line 11)**	$ 99.7922

[1] Residential Fuel Oil - HECO-409, page 1, line 3
Diesel Oil - HECO-411, line 6

Hawaiian Electric Company, Inc.

DERIVATION OF RESIDUAL FUEL OIL INVENTORY

Line		Energy (GWh)	
1.	Forecast Residual Fuel Oil Consumption[1]	8,030,246	Barrels
2.	Burn Rate (Line 1 / 365 days)	22,001	Barrels/Day
3.	35 Day Inventory (Line 2 X 35 days)	770,024	Barrels
4.	Fuel Price[2]	$ 65.2243	$/Barrel
5.	Residual Fuel Oil Inventory (Line 3 x Line 4)	$ 50,224	$000

[1] See HECO-404, line 4, column A.
[2] See HECO-408, line 7.

Hawaiian Electric Company, Inc.

2007 Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony)

Sales and Peak Forecast dated August 2006

Maintenance Schedule dated July 21, 2006 (AES @ 10 Days)

Fuel Prices August 2006 Contract Prices

	Mbtu Consumption					Net MWh Generation					Net Heat
Month	Kahe	Waiau	Honolulu	Diesel	Total	Kahe	Waiau	Honolulu	Diesel	Total	Rate
Jan	2,810,575	1,001,587	139,759	40,084	3,992,006	273,587	83,727	11,262	1,210	369,786	10,795
Feb	2,964,056	1,114,344	166,502	49,590	4,294,492	291,364	96,435	13,448	1,596	402,843	10,660
Mar	2,921,409	860,278	164,260	34,829	3,980,776	286,027	72,860	13,123	1,026	373,036	10,671
Apr	2,927,541	743,091	91,511	38,233	3,800,376	285,705	62,986	7,220	1,253	357,164	10,640
May	2,659,987	1,211,915	171,408	34,040	4,077,350	259,389	104,525	13,879	1,030	378,823	10,763
Jun	2,752,274	1,198,701	177,827	45,772	4,174,575	269,297	104,585	14,352	1,369	389,603	10,715
Jul	2,907,673	1,259,812	171,023	50,792	4,389,300	284,892	109,621	13,806	1,625	409,944	10,707
Aug	2,944,559	1,298,855	215,666	93,014	4,552,095	288,729	113,532	17,715	3,346	423,322	10,753
Sep	3,112,713	1,130,684	162,446	47,611	4,453,454	305,089	98,830	13,092	1,360	418,371	10,645
Oct	3,205,925	1,167,175	211,532	90,361	4,674,993	315,254	102,479	17,300	3,350	438,383	10,664
Nov	2,995,672	920,683	98,738	33,327	4,048,420	292,696	79,716	7,903	912	381,227	10,619
Dec	3,048,607	799,136	59,597	35,350	3,942,691	297,728	66,368	4,629	1,043	369,768	10,663
Total	35,250,991	12,706,261	1,830,272	593,004	50,380,528	3,449,757	1,095,664	147,729	19,120	4,712,270	10,691
	10,218	11,597	12,389	31,015	10,691	73.2%	23.3%	3.1%	0.4%	100.0%	
Sub. DG					235,037					23,016	10,212
HECO w/DG					50,615,565					4,735,286	10,689

LSFO heat content = 6.2 million BTU per barrel
Diesel heat content = 5.86 million BTU per barrel

AES Hawaii, Inc

2007 Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony)

Sales and Peak Forecast dated August 2006

Maintenance Schedule dated July 21, 2006 (AES @ 10 Days)

Fuel Prices August 2006 Contract Prices

Month	2 Boiler Operation			1 Boiler Operation		
	MWh	Hrs	Avg MW	MWh	Hrs	Avg MW
Jan	132,883	738	180.01	0	0	0.00
Feb	119,578	664	180.01	0	0	0.00
Mar	132,495	736	180.00	0	0	0.00
Apr	128,563	714	180.01	0	0	0.00
May	132,408	736	180.00	0	0	0.00
Jun	128,477	714	179.99	0	0	0.00
Jul	132,365	735	179.99	0	0	0.00
Aug	132,495	736	180.00	0	0	0.00
Sep	128,909	716	179.99	0	0	0.00
Oct	89,381	497	179.99	21,384	238	90.00
Nov	128,434	714	180.01	0	0	0.00
Dec	132,538	736	180.01	0	0	0.00
Total	1,518,526	8,436	180.00	21,384	238	90.00

Kalaeloa Partners

2007 Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony)

Sales and Peak Forecast dated August 2006

Maintenance Schedule dated July 21, 2006 (AES @ 10 Days)

Fuel Prices August 2006 Contract Prices

	2 CT Operation			1 CT Operation		
Month	**MWh**	**Hrs**	**Avg MW**	**MWh**	**Hrs**	**Avg MW**
Jan	109,973	556	197.96	15,957	177	90.00
Feb	0	0	0.00	39,361	437	90.00
Mar	111,380	567	196.31	14,627	163	90.00
Apr	119,101	606	196.61	9,308	103	90.00
May	127,493	638	199.74	8,510	95	90.00
Jun	120,627	600	201.09	9,840	109	90.00
Jul	127,566	629	202.67	9,308	103	90.00
Aug	128,452	635	202.18	8,776	98	90.00
Sep	118,356	594	199.27	10,372	115	90.00
Oct	129,498	638	202.89	8,510	95	90.00
Nov	121,563	612	198.73	8,776	98	90.00
Dec	121,718	618	197.08	10,372	115	90.00
Total	1,335,725	6,693	199.57	153,719	1,708	90.00

H-POWER

2007 Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony)

Sales and Peak Forecast dated August 2006

Maintenance Schedule dated July 21, 2006 (AES @ 10 Days)

Fuel Prices August 2006 Contract Prices

Month	On-Peak MWH	Off-Peak MWH	Total MWH	NonFirm MWH
Jan	14,509	10,364	24,873	500
Feb	14,735	10,525	25,260	452
Mar	17,369	12,406	29,775	500
Apr	16,808	12,006	28,814	484
May	17,369	12,406	29,775	500
Jun	16,808	12,006	28,814	484
Jul	13,556	9,683	23,239	500
Aug	17,369	12,406	29,775	500
Sep	16,808	12,006	28,814	484
Oct	17,369	12,406	29,775	500
Nov	16,808	12,006	28,814	484
Dec	17,369	12,406	29,775	500
Total	196,877	140,627	337,504	5,887

H-POWER EAF of 90%

NonFirm IPP - Tesoro 6,254,736 kWh and Chevron 735,181 kWh

Substation DG Generation

2007 Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony)

Sales and Peak Forecast dated August 2006

Maintenance Schedule dated July 21, 2006 (AES @ 10 Days)

Fuel Prices August 2006 Contract Prices

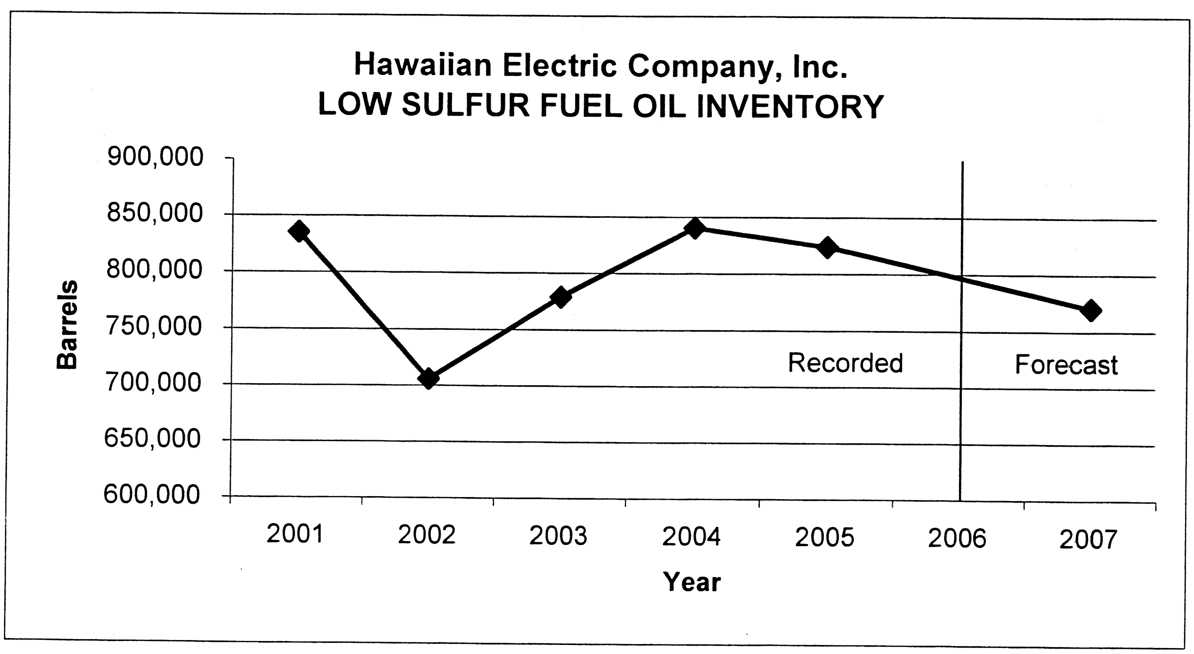
Month	System Level MWh	MBtu
Jan	1,697	17,334
Feb	1,476	15,073
Mar	1,948	19,896
Apr	1,860	18,992
May	2,037	20,801
Jun	1,860	18,992
Jul	1,948	19,896
Aug	2,150	21,956
Sep	1,870	19,092
Oct	2,150	21,956
Nov	2,057	21,002
Dec	1,963	20,047
Total	23,016	235,037
Net Heat Rate (Btu/kWh)	10,212	

	MWh
AES	1,539,910
KPLP	1,489,444
HPOWER	337,504
NonFirm	5,887
Total IPP	3,372,744

Hawaiian Electric Company, Inc.

LOW SULFUR INVENTORY 2001-2005

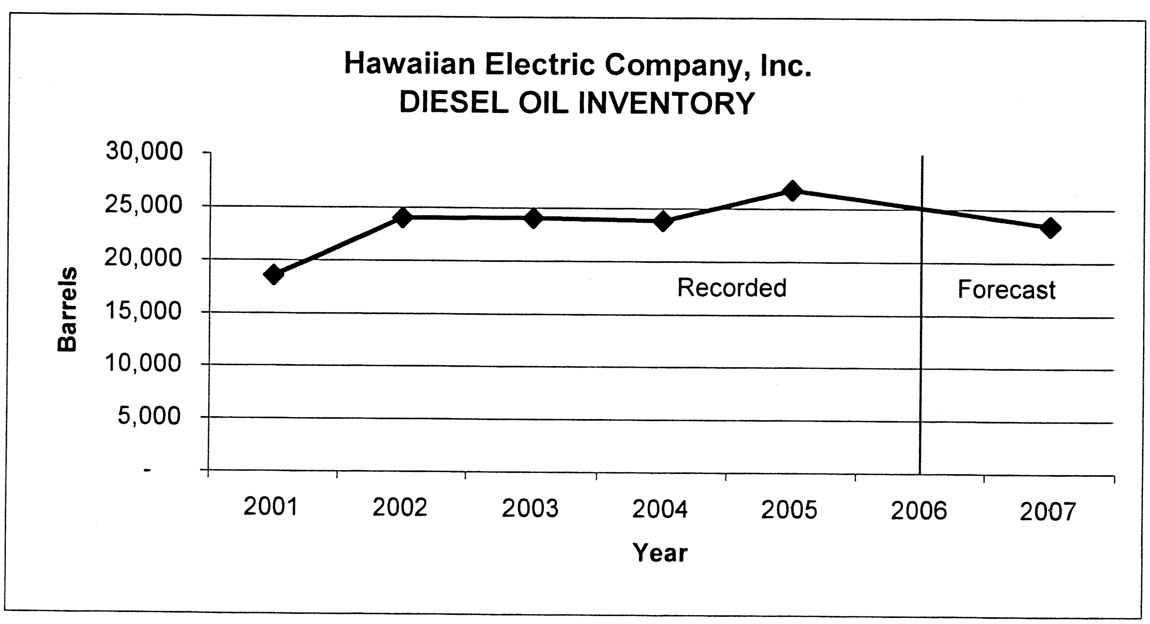
Line	Year	(A) Barrels Consumed Per Day	(B) Average Ending Inventory (Barrel)	(C) = (B) / (A) (C) Average Days Supply
1.	2001	20,272	835,100	41
2.	2002	20,888	705,692	34
3.	2003	20,974	778,717	37
4.	2004	22,290	840,342	38
5.	2005	21,515	823,872	38
6.	2001 - 2005 Average	21,188	796,745	38



Hawaiian Electric Company, Inc.

DIESEL OIL INVENTORY 2001-2005

Line	Year	(A) Barrels Consumed Per Day	(B) Average Ending Inventory (Barrel)	(C) = (B) / (A) (C) Average Days Supply
1.	2001	60	18,522	307
2.	2002	61	23,992	393
3.	2003	79	24,010	306
4.	2004	169	23,827	141
5.	2005	325	26,730	82
6.	2001 - 2005 Average Central Station Inventory	139	23,416	
7.	DG Inventory		1,457	
6.	Total Diesel Oil Inventory		24,873	



Hawaiian Electric Company, Inc.

**DERIVATION OF DIESEL FUEL OIL INVENTORY
DERIVED ON DAILY CONSUMPTION BASIS**

Line			
1.	**Forecast Diesel Fuel Oil Consumption**	101,195	Barrels
2.	**Burn Rate (Line 1 / 365 days)**	277	Barrels/Day
3.	**35 Day Inventory (Line 2 X 35 days)**	9,704	Barrels
4.	**Continuous 24 Hour Consumption**[1]	5,420	Barrels/Day
5.	**Diesel Fuel Oil Inventory (Line 3 x Line 4)**	1.8	Days

[1] Assumption: W9 and W10 are run at 53 MW and 50 MW respectively for 24 hours.
W9: {[198.6939 + (7.8497 * 53) + (.02922 * 53^2)] * 24} / 5.86 = 2,853.82 Barrels/Day
W10: {[191.3958 + (7.2757 * 50) + (.02851 * 50^2)] * 24} / 5.86 = 2,565.69 Barrels/Day
W9 + W10 combined = 5,419.51 Barrels/Day

Hawaiian Electric Company, Inc.

DAYS OF FULL LOAD CONSUMPTION

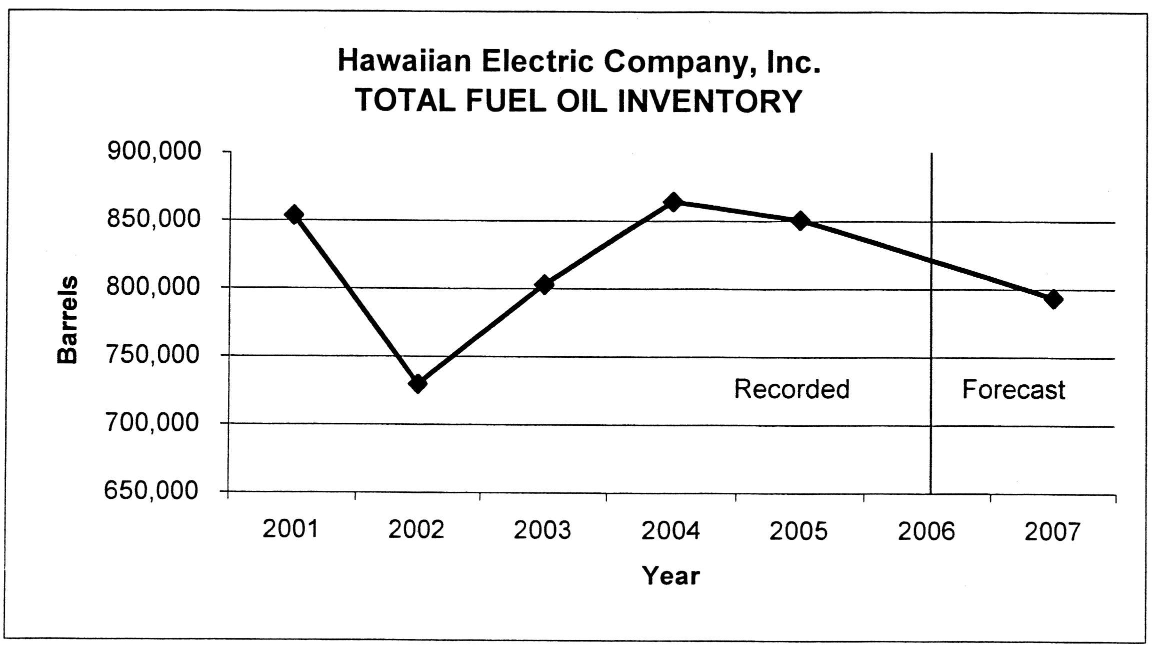
Line			
1.	**HECO's Test Year Diesel Inventory**	24,873	Barrels
2.	**HECO's Full Load Consumption**	5,420	Barrels/Day
3.	**Days at Full Load Consumption**	4.6	Days

[1] Assumption: W9 and W10 are run at 53 MW and 50 MW respectively for 24 hours.
W9: {[198.6939 + (7.8497 * 53) + (.02922 * 53^2)] * 24} / 5.86 = 2,853.82 Barrels/Day
W10: {[191.3958 + (7.2757 * 50) + (.02851 * 50^2)] * 24} / 5.86 = 2,565.69 Barrels/Day
W9 + W10 combined = 5,419.51 Barrels/Day

Hawaiian Electric Company, Inc.

HISTORICAL FUEL INVENTORY COMPARED WITH TEST YEAR AVERAGE MONTHLY INVENTORY

Line	Year	(A) L S F O Barrels	(B) Diesel Barrels	(C) = (A) + (B) (C) Total Barrels
1.	2001	835,100	18,522	853,622
2.	2002	705,692	23,992	729,684
3.	2003	778,717	24,010	802,727
4.	2004	840,342	23,827	864,169
5.	2005	823,872	26,730	850,602
6.	2001 - 2005 Average	796,745	23,416	820,161



HECO T-5
DOCKET NO. 2006-0386

TESTIMONY OF
DANIEL S. W. CHING

DIRECTOR
POWER PURCHASE DIVISION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: PURCHASED POWER EXPENSE

INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel S. W. Ching and my business address is 475 Kamehameha Highway, Pearl City, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Director of the Power Purchase Division within the Power Supply Services Department. My experience and educational background are listed in HECO-500.

Q. What is your responsibility as a witness in this proceeding?

A. My testimony will support the 2007 test year estimate for purchased power expense. It will cover both purchased energy and capacity expenses.

PURCHASED POWER EXPENSES

Q. What are the 2007 test year estimated purchased power expenses?

A. The normalized 2007 test year purchased power expense estimate is $386,108,107. This includes:

$277,432,042	purchased energy expenses
<u>$108,676,065</u>	firm capacity expenses
<u>$386,108,107</u>	total purchased power expenses

(See HECO-501.)

Q. How are purchased energy expenses determined?

A. Purchased energy expenses are based on the projected amount of energy to be purchased by, or made available to, HECO in the test year and the contract pricing terms for the various purchased power producers. These energy terms vary for different purchased power producers.

Q. How are firm capacity expenses determined?

A. Firm capacity expenses are based on the individual contract terms for delivery of firm capacity by the purchased power producers. These capacity terms are different for the various contracts.

Q. What purchased power contracts ("contracts" or "PPAs") does HECO have?

A. HECO purchases energy and capacity from three firm capacity and two as-available energy power producers, as shown on HECO-502. These are:

Firm:

1) AES Hawaii, Inc. ("AES Hawaii"), formerly known as AES Barbers Point, Inc.,
2) Honolulu Program of Waste Energy Recovery ("H-POWER"), and
3) Kalaeloa Partners, L.P. ("Kalaeloa");

As-available:

1) Chevron, and
2) Tesoro, formerly known as Hawaiian Independent Refinery, Inc.

PURCHASED ENERGY

Energy (kilowatt-hours) Purchased

Q. What is HECO's normalized estimate of the amount of energy to be purchased in the test year?

A. For the normalized 2007 test year, HECO estimates approximately 3,373 gigawatthours (GWh) in purchased energy. This represents approximately 41.59% of the total net energy produced of 8,109 GWh required in test year 2007 as shown in HECO-403. A breakdown of this estimate by purchased power producers is shown in HECO-503.

Q. How was the normalized estimate determined?

A. The test year estimate of energy purchases was derived from the HECO 2007

Production Simulation - (Rate Case - 2007 Test Year - Direct Testimony) dated September 28, 2006.

Q. How were energy purchases for operating year 2007 forecasted?

A. Three methods were used to develop the 2007 forecast of purchased energy. These are:

1) economic dispatch,
2) power dispatch schedules, and
3) historical data review for as-available sources.

Q. What method of forecasting purchased energy was applied to each of the providers of purchased energy (also known as Independent Power Producers ("IPPs"))?

A. Energy purchases from AES Hawaii and Kalaeloa are forecasted based on the expected economic dispatch of their facilities for the test year. Both of these facilities are fully dispatchable by HECO (between upper and lower levels in accordance with their contracts) and hence they are dispatched in the most economic fashion for our system, taking into account any applicable system constraints. H-POWER energy deliveries are forecasted using power dispatch schedules, historical trends, and contract requirements. The as-available producers' purchased energy amounts are forecasted based on historical trends.

Q. How was <u>economic dispatch</u> used to forecast the amount of energy provided by large firm power producers?

A. Kalaeloa and AES Hawaii were simulated as generating units in the production simulation model in a manner similar to HECO's own generating units. (Mr. Ross Sakuda described this production simulation model earlier in HECO T-4.) However, instead of using heat rate curves as the basis for determining production costs for Kalaeloa and AES Hawaii, the contractual payment provisions for energy and variable O&M for each producer were translated into second order equations. Simulating Kalaeloa and AES Hawaii as generating units permits their energy costs to be compared to the costs of energy from HECO's own units for the purpose of dispatching the required energy in the most economical fashion. This simulation provides the optimum or lowest cost operation of the generation on our system consistent with the "real world" constraints of HECO's electrical system.

Q. How were power dispatch schedules, historical trends and contract requirements used to forecast the amount of energy provided by H-POWER?

A. For H-POWER a typical daily dispatch schedule is developed based on the firm capacity obligation of this producer and the contract energy targets. The H-POWER plant normally operates around 46 MW during the fourteen-hour per day on-peak period during the entire year. During the off-peak hours for the months of December through May, the contract provides that HECO shall accept from H-POWER up to 40 MW during week days and 25 MW on Saturdays, Sundays and holidays. However, in past years, H-POWER requested HECO to waive this off-peak provision, in order to help optimize waste disposal at H-POWER. HECO's position is that it cannot agree up front to waive the contract requirement due to technical limitations associated with the minimum loading on HECO's units during system minimum loads at night during the December through May period. Unforeseeable technical constraints on the Oahu grid, including the transmission system and constraints at night due to low loading on HECO's generating units may require HECO to curtail H-POWER as well as other generating units. However, HECO is willing to accept up to 46 MW during the off-peak hours between December 1 and May 31 as system conditions allow.

HECO now anticipates H-POWER producing up to 46 MW at all hours of the day and night. During other months of the year the H-POWER plant is normally operating up to 46 MW during the off-peak period.

The forecast assumes that the plant is normally completely shut down for three weeks every year in the spring for routine maintenance of each of the two boilers. Also, each of the two boilers is typically taken off line for additional maintenance in the fall and in the winter.

Q. How is <u>historical data review for as-available sources</u> used in HECO's test year cost of purchased energy?

A. The estimates of purchased energy from Chevron and Tesoro were based on the average of the respective purchases over the most recent five-year period. They are summarized in HECO-504.

Q. How does the test year estimate of energy purchases compare with the historical level of energy purchases?

A. For the firm capacity producers, the test year energy purchases are estimated to be close to the actual 2005 energy purchases. The comparison of test year energy purchases versus historical energy purchases is presented in HECO-505.

Q. Please summarize why HECO's estimate of purchased energy is reasonable.

A. The test year purchased energy estimate is reasonable because of the detailed methodology used to derive the operating forecast and because it is consistent with historical production, taking into consideration known changes to our system. Furthermore, this methodology is consistent with the way in which we operate our system.

<u>Purchased Energy Expenses</u>

Q. What are the estimated purchased energy expenses for the 2007 test year?

A. The estimated purchased energy expenses for the 2007 test year are $277,432,042. (See HECO-501 for summary and HECO-506 for breakdown by IPPs.)

Q. How did HECO determine the test year estimate of purchased energy expenses?

A. For the Chevron and Tesoro as-available energy contracts and the H-POWER contract, purchased energy expenses were determined by multiplying the estimated energy deliveries (kilowatt-hours) by the applicable contract prices. For the AES Hawaii contract, purchased energy expenses were determined by multiplying the estimated AES Hawaii energy deliveries (kilowatt-hours) by: (1) the applicable fuel and fuel-related ("variable O&M") components of the contract energy charge, and (2) multiplying the estimated kilowatt-hours made available by AES Hawaii for dispatch by the applicable non-fuel ("fixed O&M") component of the contract energy charge. For the Kalaeloa contract, purchased energy expenses were determined by multiplying the estimated Kalaeloa energy deliveries (kilowatt-hours) by the applicable fuel, fuel-related ("additive"), and non-fuel ("O&M") components of the contract energy charge.

Q. How were the test year purchased energy prices determined?

A. The purchased power contracts have two general types of pricing provisions. These are:

1) pricing that uses the avoided energy cost rates and the Schedule Q rates that are filed quarterly with the Commission, and
2) pricing that is derived from "formulas" specified in the individual PPAs.

As shown in the last column of HECO-502, only Kalaeloa and AES Hawaii are paid by contract-specific formulas. Chevron, Tesoro, and H-POWER are paid based on avoided energy cost rates. The H-POWER PPA further specifies certain adjustments to the avoided energy cost rates, as described below.

Q. How were the test year purchased energy rates determined for producers who are paid in accordance with the avoided energy cost rates and Schedule Q rates filed quarterly with the Commission?

A. Purchased energy prices were derived for these producers based on their respective contract pricing terms and the test year estimates for fuel prices. In H-POWER's case, there are floor level rates (or minimum purchased on-peak and off-peak energy rates) in its contract based on the avoided energy costs in effect at the time the Commission approved that contract. Floor level rates were originally established by Title 6, Chapter 74, Hawaii Administrative Rules, Standards for Small Power Production and Cogeneration in the State of Hawaii and in force during the negotiation of the H-POWER contract. (However, the minimum purchase rate was later eliminated by the Legislature in 2004 (see HRS 269-27.2).) If the H-POWER contract floor level rates are higher than the calculated test year energy prices, then the floor level rates are used to determine the purchased energy expense.

Also, in H-POWER's contract, if the avoided energy cost rates reach certain thresholds in the contract, the on-peak and off-peak energy payment rates are the filed on-peak or off-peak avoided energy costs as applicable, less a discount equal to a percentage of the differential between such rates and the respective floor level rates in the contract. If the calculated test year energy prices based on the filed avoided energy costs reach certain thresholds, then the discounted avoided energy cost rates are used to determine the purchased energy expense for H-POWER.

<u>H-POWER Energy Payment Rate</u>

Q. Under what PPA does HECO purchase energy from H-POWER?

A. The H-POWER energy price is based on the Purchase Power Contract dated

March 10, 1986, as amended by the Firm Capacity Amendment (dated April 8, 1991). The Purchase Power Contract was approved by the Commission in Decision and Order No. 8698 (March 31, 1986) in Docket No. 5514. The Firm Capacity Amendment (Docket No. 6983) was approved by the Commission in Decision and Order No. 11700 (dated June 30, 1992).

Q. How is the energy to be produced by H-POWER priced?

A. Under the amended agreement, the purchased energy prices are based on the higher of avoided energy cost rates filed with the Commission quarterly or floor level rates, and with adjustments specified in the PPA. For energy delivered up to 644 MWh/day on-peak and 250 MWh/day off-peak, H-POWER has floor level rates of 7.21 cents/kWh and 5.60 cents/kWh, respectively. For energy delivered in excess of the above stated amounts, the floor level rates are 6.7 cents/kWh on-peak and 5.19 cents/kWh off-peak.

If the filed avoided energy cost rates reach certain thresholds, certain adjustments to the purchased energy prices apply. The adjustments are specified in Appendix D of the Firm Capacity Amendment. For example, if the on-peak avoided energy cost is 11.16 cents/kWh, a 25% discount is applied to the differential between the on-peak avoided energy cost and the respective floor level rates. The rate for the on-peak energy in this example would be discounted from 11.16 cents/kWh to 10.172 cents/kWh. If the off-peak avoided energy cost is 8.50 cents/kWh, a 25% discount is applied to the differential between the off-peak avoided energy costs and the respective floor level rates. The rate for off-peak energy in this example would be discounted from 8.50 cents/kWh to 7.775 cents/kWh.

Kalaeloa Energy Payment Rate

Q. Under what terms and conditions does HECO purchase energy from Kalaeloa?

A. HECO purchases energy from Kalaeloa under a PPA dated October 14, 1988, as amended by Amendment No. 1 (dated June 15, 1989), Restated Amendment No. 2 (dated February 9, 1990), Amendment No. 3 (dated December 10, 1991), and Amendment No. 4 (dated October 1, 1999). The amended PPA was approved by the Commission in Decision and Order Nos. 10369 (October 16, 1989), 10824 (October 31, 1990), 11494 (February 24, 1992) (ratifying Amendment No. 3) in Docket No. 6378, and 17647 (March 30, 2000) in Docket No. 00-0001 (ratifying Amendment No. 4). In addition, HECO and Kalaeloa signed Amendment No. 5 (dated October 12, 2004), and Amendment No. 6 (dated October 12, 2004). Amendment No. 5 and Amendment No. 6 have provisions which govern the purchase of energy when Kalaeloa is dispatched at 180,000 kW or greater. Amendment Nos. 5 and 6 were approved by the Commission in Decision and Order No. 21820 in Docket No. 04-0320 (May 13, 2005).

Q. Please give a brief description of Amendment Nos. 5 and 6.

A. Amendment No. 5 is titled Confirmation Agreement Concerning Section 5.2B(2) of Power Purchase Agreement and Amendment No. 5 to Power Purchase Agreement dated as of October 12, 2004. It provides for the purchase of 9 megawatts ("MW") of firm capacity that already exists at the Kalaeloa facility. Amendment No. 6 is titled Agreement for Increment Two Capacity and Amendment No. 6 to Power Purchase Agreement Between Hawaiian Electric Company, Inc. and Kalaeloa Partners, L.P. dated as of October 12, 2004. It provides for the purchase of up to an additional 20 MW of firm capacity as a result of mechanical efficiency upgrades to the facility's two combustion turbines.

Q. How is energy produced by Kalaeloa priced?

A. Kalaeloa's energy payment rate is divided into three components:

1) fuel,
2) fuel additive, and
3) non-fuel (O&M).

HECO's energy payments to Kalaeloa also must take into account the minimum purchase obligations (and corresponding shortfall charges) in the Kalaeloa PPA.

Q. What is the test year Kalaeloa energy expense?

A. The estimated Kalaeloa test year energy expense is $168,426,297:

1) fuel, $145,372,206;
2) fuel additive, $2,374,257; and
3) non-fuel (O&M), $20,679,834.

Q. How is Kalaeloa's <u>fuel component</u> determined for the test year?

A. The fuel component is based on formulas in the PPA, which depends on the fifteen-minute load of the facility (in megawatts), the fifteen-minute kWh purchased from the facility, and the number of combustion turbines being dispatched. The fuel component is adjusted monthly based on changes in Kalaeloa's actual low sulfur fuel oil ("LSFO") cost from a base fuel cost of $19.50 per barrel with a gross heating value of 6,000,000 BTU per barrel. At full output of 180 MW and above, with three generators operating, the base contract price is 2.77 cents/kWh (before application of the LSFO adjustment).

Q. What is the fuel price assumed for Kalaeloa?

A. The test year fuel price for low sulfur residual oil for the Kalaeloa facility is $67.597 per barrel.

Q. How was this price determined?

A. The Kalaeloa fuel price is based on the fuel oil contract between Hawaiian Independent Refinery, Inc. ("HIRI") and Kalaeloa. (See Exhibit C of the Application for approval of the Kalaeloa Power Purchase Contract, Docket No. 6378.) The test year fuel component price is shown in HECO-WP-501.

Q. How does it compare to oil prices for other HECO units?

A. The Kalaeloa price (per million Btu) is slightly higher than HECO's price due primarily to the treatment necessary to remove contaminants so that the fuel can be burned by Kalaeloa's combustion turbines.

Q. How is Kalaeloa's <u>fuel additive component</u> determined for the test year?

A. The fuel additive component as used for the test year follows the change that was incorporated in Amendment No. 5 and more fully described in Docket No. 04-0320, Application dated November 5, 2004, pages 17 to 21. As of the December 2005 invoice for energy deliveries, the formula for the "Post-Transition Date" is applied and this is reflected in the 2007 Test Year expense calculation in HECO-WP-501.

Q. How is Kalaeloa's <u>non-fuel component</u> determined for the test year?

A. As a result of Amendment No. 5, the non-fuel, or O&M, component is comprised of three rates: 1) a base rate of 0.96 cents/kWh for all kilowatt-hours purchased up to the minimum energy purchase obligation, 2) a Variable O&M Component rate of 0.48 cents/kWh for all kilowatt-hours purchased past the minimum energy purchase obligation when Kalaeloa is dispatched at less than 180,000 kW, and 3) a Variable O&M Component rate of 0.144 cents/kWh for all kilowatt-hours purchased past the minimum energy purchase obligation when Kalaeloa is dispatched at 180,000 kW or greater. Each of these rates is escalated annually by changes in the Gross National Product Implicit Price Deflator ("GNPIPD").

Q. What GNPIPD did HECO use for test year 2007?

A. The GNPIPD used for test year 2007 for the purposes of forecasting Kalaeloa O&M escalation is 116.138, which is the forecasted fourth quarter 2006 GNPIPD.

Q. How was the fourth quarter 2006 GNPIPD forecasted?

A. The Energy Information Administration Annual Energy Outlook 2006 (Table A19, Page 161, published in February 2006) forecast of the gross domestic product (GDP) chain-type price index was used to estimate quarterly escalation values. These quarterly escalation values were used with the actual first quarter 2006 GNPIPD value to produce the forecasted GNPIPD shown in HECO-WP-502.

Q. What is HECO's minimum energy purchase obligation under the Kalaeloa PPA?

A. HECO is required to purchase a minimum of 1,235 GWh, as adjusted based on the ratio of the actual Equivalent Availability Factor ("EAF") (not to exceed 92%) to a base EAF of 85%.

Q. What level of Kalaeloa energy purchases is estimated for the 2007 test year?

A. In the test year, HECO estimates that it will purchase 1,489 GWh from Kalaeloa. (See HECO-503.)

Q. What is the forecasted EAF for Kalaeloa for the test year?

A. The estimated EAF for Kalaeloa for the test year is 92.00%.

Q. How was the estimated EAF determined?

A. The 92.00% EAF for the Kalaeloa plant was estimated as the 12-month test year EAF based on a review of the recent historical EAF record, the present plant performance and practices, and the projected performance of the plant over the next few years. The 2007 test year value is lower than the 93.03% EAF that was used in the 2005 Rate Case (Docket No. 04-0113, HECO-WP-501). The 92%

value was not quantitatively calculated but represents a general approximation after considering the above noted factors, which are discussed in further detail below.

The historical record for Kalaeloa statistics for EAF begins at the Kalaeloa plant In-Service Date of May 23, 1991. Generally, the more recent years are considered more accurate as a predictor of future performance in that the more recent years would incorporate changes in scheduled outage patterns and the occurrence of unplanned events that might be more prevalent as the plant ages. HECO-WP-501 shows the EAF and EFOR statistics for the entire plant operation. The initial three years had various issues which required various remedies to improve performance. The Contract Year 9 EAF of 92.18% includes the major steam turbine inspection and maintenance where the entire plant was off-line. This was the first time the major steam turbine work had been performed since the In-Service Date. Such planned activities normally result in a lower EAF given the larger amount of scheduled outage time compared to the more normal year-to-year outages. The next such steam turbine outage will not occur until the year 2010 based on current projections from Kalaeloa. The scheduled outage plans for years such as 2007 are currently projected to be repeated with only minor variation as needed to support a specific maintenance activity. The forced outage events are the other component of the EAF. With Kalaeloa these have generally been in the range of 1% with the exception of Contract Years 13 and 15.

Currently Kalaeloa has been experiencing increased outage time related to water or steam leaks from the heat recovery steam generators (HRSG). This issue was summarized in a September 15, 2006 letter from HECO to Kalaeloa (HECO-WP-501). We note that Kalaeloa is taking steps to address this problem and we project that the impact on EAF will not increase substantially beyond current impact. A successful mitigation program would likely occur over several years.

The maintenance schedule in years beyond 2007 is expected to be similar to 2007 with the possible exception that the full plant outage portion will go back to the more normal 7 days rather than 9 days projected in 2007.

In past years Kalaeloa very often will complete the scheduled outage ahead of schedule. Kalaeloa has incentives through the PPA to complete the scheduled outages on time. The non-fuel component payments only occur when the plant is running. Also a higher EAF (up to a cap of 92%) increases the required minimum purchase amount (see discussion filed February 14, 1994 pursuant to Docket No. 6998 on "shortfall charges"). Also Kalaeloa can in certain circumstances incur penalties if the plant remains unavailable more than 48 hours after the scheduled completion of the outage (see PPA Section 3.2D.7). In addition there are liquidated damages if certain performance criteria pertaining to EAF and EFOR are not met (see PPA Section 3.2E).

The improvement in EAF gained from completing the scheduled outage ahead of schedule is counterbalanced by the increased outage time related to events such as HRSG leaks. If the leak is not too severe, a forced outage is averted and the event does not contribute to an EFOR event but is statistically handled similar to a scheduled outage as far as impact on EAF. HRSG leaks can more than use up all of the saving in outage time that is gained by completing the normal scheduled outage ahead of time.

In summary, we project that 92% is a reasonable estimate for EAF for use in the 2007 test year.

AES Hawaii Energy Payment Rate

Q. Under what PPA does HECO purchase power from AES Hawaii?

A. HECO purchases power from AES Hawaii based on the PPA dated March 25, 1988, as amended by Amendment No. 1 (dated August 28, 1989), as modified by a letter agreement regarding "Conditional Notice of Acceptance" (dated January 15, 1990), and as amended by Amendment No. 2 (dated May 8, 2003). The PPA and Amendment No. 1 were approved by the Commission in Decision and Order Nos. 10296 (July 28, 1989) and 10448 (December 29, 1989) ("D&O 10448") in Docket No. 6177. As a result of D&O 10448, the PPA, as amended by Amendment No. 1, was modified by the letter agreement. Amendment No. 2 was approved by the Commission in Decision and Order Nos. 20292 (July 1, 2003) and 20310 (July 9, 2003) in Docket No. 03-0126.

Q. How is the energy to be produced by AES Hawaii priced?

A. AES Hawaii's energy pricing is divided into three components:

1) fuel,
2) variable O&M, and
3) fixed O&M.

Q. What is the test year AES Hawaii energy expense?

A. The estimated AES Hawaii test year energy expense is $69,502,552:

1) fuel, $41,125,866,
2) variable O&M, $1,233,968, and
3) fixed O&M, $27,142,718.

(See HECO-WP-503, page 1.)

Q. How is AES Hawaii's fuel component determined for the test year?

A. The fuel component is based on the formula in the PPA, which depends on the hourly load of the facility (in megawatts) and the hourly kWh purchased from the facility. The fuel component is adjusted semi-annually based on changes in GNPIPD from the first quarter 1987 GNPIPD. At full output the base contract price is 1.69 cents/kWh delivered (in July 1987 dollars). The calculation of the test year fuel component is shown in HECO-WP-503.

Q. What GNPIPD estimate did HECO use for test year 2007?

A. For the first six months of 2007, HECO used an estimated GNPIPD index of 115.540. This is the forecasted third quarter 2006 GNPIPD. For the last six months of test year of 2007, a GNPIPD index of 116.739 was used. This is the forecasted first quarter 2007 GNPIPD.

Q. Why were the estimated third quarter 2006 and first quarter 2007 GNPIPDs used for this adjustment?

A. The energy charge in the AES Hawaii PPA is adjusted semiannually as of January 1 and July 1 of each year based on the third quarter GNPIPD of the previous year and first quarter GNPIPD of that year, respectively.

Q. How were the GNPIPDs forecasted?

A. They were forecasted using the methodology described earlier in the discussion of GNPIPD for Kalaeloa.

Q. What value did HECO use for the first quarter 1987 GNPIPD?

A. HECO used a first quarter 1987 GNPIPD value of 72.465.

Q. How was the first quarter 1987 GNPIPD value determined?

A. The first quarter 1987 GNPIPD value of 72.465 is the value published by the Bureau of Economic Analysis on June 29, 2006.

Q. How is AES Hawaii's <u>variable O&M component</u> determined for the test year?

A. The variable O&M component consists of a base charge of 0.05 cent/kWh delivered (in July 1987 dollars) that is escalated based on changes in the GNPIPD. The calculation of the test year variable O&M component is shown in HECO-WP-503. The variable O&M component is adjusted for changes in the GNPIPD in the same method as described for the fuel component.

Q. How is AES Hawaii's fixed O&M component determined for the test year?

A. The fixed O&M component is a charge of 1.1 cents/kWh (in July 1987 dollars) escalated by changes in the GNPIPD. This charge is applied to the total kilowatt-hours available for dispatch. The calculation of the test year fixed O&M component is shown in HECO-WP-503. The fixed O&M component is adjusted for changes in GNPIPD as described in the preceding discussion for the fuel component.

PURCHASED FIRM CAPACITY

Q. What are the firm capacity expenses of the firm capacity IPPs?

A. Firm capacity payments will be made to Kalaeloa, AES Hawaii and H-POWER. The firm capacity expenses are estimated to be $108,676,065 for 2007. (See HECO-501 for summary and HECO-507 for breakdown by IPPs.)

Kalaeloa Firm Capacity

Q. How are capacity payments to Kalaeloa determined?

A. The capacity charge for the 180 MW of firm capacity provided by Kalaeloa under the PPA and Amendment Nos. 1 through 4 is $164.35 per kW per year (as adjusted from $167.51 per kW per year pursuant to Amendment No. 3). The capacity charge for the new capacity of 28 MW provided under Amendment Nos. 5 and 6 is $112 per kW per year.

On December 31, 2003, HECO and Kalaeloa Partners, L.P. executed a Consent and Agreement whereby HECO consented to Kalaeloa's upgrade of its combustion turbines by making changes to the power train portion of each combustion turbine to increase the output and efficiency of the Kalaeloa generating facility. In May, 2004, Kalaeloa completed the upgrade of the first of its two combustion turbines. In December, 2004, Kalaeloa completed the upgrade of its second combustion turbine. Each upgraded combustion turbine anticipated allowing the Kalaeloa generating facility to produce up to 10 MW of net additional capacity. Thus, with the completion of upgrades to both combustion turbines, the Kalaeloa generating facility was anticipated to produce up to 20 MW of net additional capacity.

Kalaeloa also made certain capital investments, prior to the upgrade work described above, which allows it to deliver 9 MW of net additional capacity. Following the December 2004 upgrade work and completion of an acceptance test, Kalaeloa proved to be able to deliver 28 MW of net additional capacity above the 180 MW provided for in the October 14, 1988 PPA, as amended by Amendment No. 1, Restated Amendment No. 2, Amendment No. 3, and Amendment No. 4.

<u>AES Hawaii Firm Capacity</u>

Q. How are capacity payments to AES Hawaii determined?

A. AES Hawaii capacity payments are based on the capacity charge of 4.4095 cents per available kilowatt-hour and a firm capacity commitment of 180,000 kW.

<u>H-POWER Firm Capacity</u>

Q. How are capacity payments to H-POWER determined?

A. H-POWER capacity payments are based on 4.89 cents per available kilowatt-hour during weekday on-peak periods. H-POWER's on-peak weekday firm capacity commitment is 46,000 kW. (See HECO-WP-504.)

AES Hawaii and H-POWER Plant Availability

Q. Is the AES Hawaii capacity payment a function of the EAF of that facility?

A. Yes. The capacity expense for AES Hawaii is calculated by multiplying the capacity charge of 4.4095 cents per available kilowatt-hour times the EAF times the number of hours in a year times its committed capacity of 180,000 kW.

Q. Historically, what has been the EAF of the AES Hawaii facility?

A. During the period September 1, 1992 through July 31, 2006, AES Hawaii had an average EAF of 97.06%.

Q. What is the estimated EAF for the AES Hawaii facility for test year 2007?

A. The estimated EAF for the AES Hawaii facility for test year 2007 is 97.64%. This is higher than the average EAF of 97.06% because AES' boiler outages occur now every 18 months, as compared to every 12 months in the earlier years, upon which the average EAF number is based.

Q. Is the capacity expense for H-POWER a function of that facility's availability?

A. Yes. The H-POWER capacity payments are calculated using a rate of 4.89 cents per available kilowatt-hour. HECO-WP-505 shows that for the 14th contract year (July 1, 2005 through June 30, 2006), the On-peak Availability, as defined in the PPA, is 85.51%.

Q. Historically, what has been H-POWER's On-peak Availability?

A. During the first Contract Year of the Firm Capacity Amendment, H-POWER's On-peak Availability (also known as the Availability Factor ("AF") in the contract) was 92.96%. The AF fell to a low of 72.99% in the 10th contract year, due to a catastrophic generator failure. During the 11th contact year, the AF was 91.61%, during the 12th year it was 86.41%, during the 13th year 87.26%, and during the 14th year it was 85.51%. Discounting the AF of the 10th contract year, H-POWER's average AF over the last 5 years excluding Contract Year 10 (Contract Years 9, 11, 12, 13, 14) is 86.63%, while their average availability factor from the first Contract Year through the 14th contract year is 87.31%. (See HECO-WP-505.)

HECO estimates an average of 87% AF for the 2007 test year and beyond. This estimate is based upon past performance but may prove to be conservative based upon continuous improvements H-POWER has made to its facility to enhance the facility's ability to stay on line generating power. Those improvements include, but are not limited to:

1) Improved combustion knowledge and monitoring of waste, particularly in regards to the variable composition and characteristics of the waste (refuse derived fuel).
2) Replacement and improvement of electrical equipment such as protective relays to allow H-POWER to stay on line generating power during frequency excursions.
3) Changes to power and control circuitry for motor drives, which allows H-POWER to ride through voltage excursions on the Oahu grid.
4) Installation of new computer electrical memory boards for maintaining Induction Draft fans, and furnace supervisory combustion control logic.
5) Revised maintenance schedules for primary and secondary superheater tubes replacements, which allow the boilers to improve availability and improve predictability.
6) Replacement of 80% of the internal components of the electrostatic precipitators and controls upgrades to the system.
7) On-line cleaning using blasting techniques while the boilers are running

(2006).

AES Hawaii Availability Bonus

Q. Are there any other payments that would be due to AES Hawaii during the test year 2007?

A. Yes. Per Section 5.2 of the AES Hawaii PPA, AES Hawaii will be paid an Availability Bonus if the EAF for the facility exceeds 91% on average for the current and prior contract years.

Q. What is the purpose of the Availability Bonus?

A. The Availability Bonus is in the PPA to provide an incentive for the AES Hawaii plant to achieve high levels of availability. This, in turn, helps in providing reliable service to HECO customers.

Q. What level of EAF is being used for calculation of the Availability Bonus?

A. For the calculation of the Availability Bonus, the assumed EAF is 97.13%, which is an estimate of the two year running average EAF for Contract Years 14 and 15 in accordance with the terms of the PPA. Refer to HECO-WP-503.

Q. How does this EAF compare with the historical performance of AES Hawaii?

A. Thus far, the AES Hawaii plant has been rather reliable. From September 1, 1992 through July 31, 2006, the average EAF was 97.06%. This period represents the first through thirteenth Contract Years and the first ten months of the fourteenth Contract Year.

Q. How is the Availability Bonus calculated?

A. For each 1/10th of a percentage point that the EAF is over 91% on average for two consecutive contract years, HECO pays AES Hawaii $15,000 in 1987 dollars. This is escalated using the formula provided in Section 8.lC. of the PPA.

Q. What is the expected Availability Bonus for the test year?

A. This bonus is expected to be $1,189,465. The calculation for this is shown on HECO-WP-503.

OTHER MATTERS

Q. Does HECO expect to purchase energy during the test year from sources other than the three firm capacity and two as-available energy producers identified above?

A. Yes. There is a HECO initiative sponsored by the Energy Projects Department to seek proposals from non-utility photovoltaic (PV) developers to install a PV system on HECO's Archer Substation rooftop, located at HECO's Ward Avenue facilities. The developer selected would sell electric energy from the PV installation, produced by sunlight, to HECO under a PPA.

Q. Please describe the Ward Avenue PV project.

A. HECO plans to issue a request for proposal ("RFP") in January 2007 to solar-energy companies to build, own and operate one or more PV systems on the rooftop of the Archer Substation. HECO would purchase the PV energy and would have an option to acquire the PV system after several years. Based on HECO's preliminary assessment, PV systems totaling approximately 155 kilowatts of direct current (kW_{dc}) power output could be accommodated on the Archer Substation rooftop. The project is planned to be in operation by December 1, 2007.

Q. Why is HECO pursuing this PV project?

A. HECO's draft preferred plan developed for its third integrated resource planning cycle ("IRP-3") includes the installation of commercial PV systems at utility facilities. As described in the IRP-3 Report, filed to the PUC in Docket No. 03-0253, the primary intent of these PV systems is to help HECO meet its Renewable

Portfolio Standards ("RPS") requirements and to increase the use of PV on Oahu.

Q. Is the proposed Ward Avenue PV project consistent with the draft preferred plan of IRP-3?

A. Yes it is, notwithstanding that the size of the proposed project and ownership structure differs somewhat from what was described in IRP-3.

Q. Please explain this in more detail.

A. At the time the IRP-3 Report was prepared in October 2005, HECO envisioned installation of up to three 100 kW blocks of PV at HECO sites in the late 2007 timeframe. The IRP-3 Report noted that the actual amount of PV and timing for its installation would depend on siting, economic, and other factors associated with required approvals for installation. As described above, HECO determined that approximately 155 kW_{dc} of PV could be located on the Ward Avenue Archer Substation rooftop. Additional PV can be installed at HECO's Ward Avenue location if integrated into parking shade structures, but HECO is deferring such PV development to a later time beyond the 2007 test year due to the added complexity and costs of installing support columns and framework.

Q. Please describe the ownership structure.

A. When HECO established its 2007 test year revenue requirements for this rate case, HECO intended to own the PV systems. Thus, the Company included the capital costs of Company-owned PV systems at Ward Avenue in its test year plant additions and reflected associated state tax credits in its test year revenue requirements. After subsequent evaluation (and after it was possible to revise the Company's revenue requirements), it was recognized that since HECO as a regulated utility cannot claim the 30% federal renewable energy tax credit, such utility-owned PV would ultimately be more costly than PV that is developed and owned by a non-utility entity. Based on this, HECO determined that it would be prudent to seek proposals from non-utility PV developers to build, own, and operate the PV systems and sell the PV electricity to HECO. This arrangement enables full use of available federal renewable energy tax credits.

Q. What PUC approvals are required?

A. The developer selected would sell energy from the PV installation to HECO under a PPA, which is subject to approval by the Commission. Use of the Archer Substation rooftop by the PV developer would be governed by a site licensing agreement which is also subject to approval by the Commission.

Q. Will HECO be revising its test year estimates to reflect this non-HECO entity ownership structure?

A. Yes. HECO will make the proper adjustments at the first available opportunity. However, the Company has developed preliminary estimates for this project.

Q. What is the preliminary estimate of test year capital costs for this project under the non-HECO entity ownership structure?

A. HECO will incur capital costs of approximately $400,000 to prepare the Archer Substation building to accommodate the PV installation and to install additional performance monitoring and display equipment not normally provided by a PV developer. The additional monitoring and display equipment will allow HECO to gain more detailed performance information from the PV system, which in turn will support HECO's renewable energy educational efforts and development of potential programs such as green pricing.

Q. What is the preliminary estimate of test year purchased power expense that HECO will incur for the project?

A. As described earlier the PV system will be placed in service on or about

December 1, 2007. The estimated amount of energy production from the system for the month of December is 13,000 kWh. Although HECO's purchased energy costs from the system remain to be determined via development of a PPA, HECO anticipates purchased energy costs of between $0 .16 and $ 0.21 per kWh. This results in a purchased energy cost ranging from $ 2,080 to $ 2,730 for the month of December.

Q. Is HECO is seeking rate recovery in this rate case for the estimated cost of purchased energy from this PV facility?

A. Once a PV power supplier has been selected through the planned RFP process, power purchase expenses and the production simulation may be adjusted at the next available opportunity to reflect the estimated PV energy purchases in 2007, although it is not expected that the purchased energy amount or expense would be significant in 2007 given the estimated in-service date of December 2007.

CONCLUSION

Q. Please summarize your testimony.

A. For the normalized 2007 test year, HECO estimates purchasing approximately 3,373 GWh from three firm capacity and two as-available IPPs. The 2007 test year purchase energy costs, which are summarized in HECO-506, are $277,432,042. The 2007 test year purchase capacity costs, which are summarized in HECO-507, are $108,676,065. The 2007 test year total purchase power expenses, which are summarized in HECO-501, and for which HECO is seeking rate recovery, are $386,108,107. This amount does not include the projected cost of purchased energy from the proposed Archer Substation PV installation during the 2007 test year.

Q. Does this conclude your testimony?
A. Yes.

Hawaiian Electric Company, Inc.
DANIEL S. W. CHING
EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway P. O. Box 2750 Honolulu, Hawaii 96840
Position:	Director, Power Purchase Division
Years of Service:	34 years
Education:	Master of Business Administration University of Hawaii, 1980 Master of Science in Electrical Engineering University of Michigan, 1972 Bachelor of Science in Electrical Engineering University of Hawaii, 1971
Other Qualifications:	Registered Professional Engineer - Hawaii Electrical Branch
Experience:	1994 - Present Director, Power Purchase Division 1990 - 1994 Purchased Power Contracts Administrator Generation Planning Department Hawaiian Electric Company, Inc. 1987 - 1990 Senior Customer Engineer Distribution Engineering Department Hawaiian Electric Company, Inc. 1983 - 1987 Customer Engineer Distribution Engineering Department Hawaiian Electric Company, Inc. 1976 - 1983 Electrical Engineer System Planning Department Hawaiian Electric Company, Inc. 1972 - 1976 Designer Engineering Department Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

TOTAL PURCHASED POWER EXPENSES
Recorded 2005 and 2007 Test Year Estimate

	Reference	2005 Recorded	2007 Test Year Estimate
Energy Payments	HECO-506	232,488,963	277,432,042
Firm Capacity Payments	HECO-507	106,776,688	108,676,065
Total Purchase Power Expense		339,265,651	386,108,107

Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

PURCHASED POWER CONTRACTS WITH INDEPENDENT POWER PRODUCERS

Contract	Contract Capacity MW	Type	Payment Terms
AES Hawaii	180	Firm	Non-escalating capacity payment paid on a kilowatt-hour available basis; O&M and fuel components escalated on a GNPIPD basis; O&M paid on both kilowatt-hour available and kilowatt-hour delivered bases; fuel component paid on basis of a formula similar to unit heat rate.
Chevron	0	As-available	Quarterly avoided energy cost.
H-POWER	46	Firm	Non-escalating capacity payment based on on-peak kilowatt-hour available; energy based on quarterly avoided energy cost with floor and ceiling rates.
Kalaeloa Partners, L.P.	208	Firm	Non-escalating capacity payment paid on a kilowatt-year basis; fuel component escalated on fuel price basis; additive component escalated on a GNPIPD basis; O&M escalated on a GNPIPD basis; fuel component paid on basis of a formula similar to unit heat rate; O&M and additive paid on kilowatt-hour delivered basis; O&M subject to minimum annual purchase.
Tesoro	0	As-available	Quarterly avoided energy cost.

Hawaiian Electric Company, Inc.

TEST YEAR PURCHASED ENERGY FORECAST

	2007 Test Year (GWh)
As-available	
1. Chevron USA (Note 2)	1
2. Tesoro (Note 2)	5
Subtotal	6
Firm Power	
1. H-POWER	338
2. Kalaeloa	1,489
3. AES Hawaii	1,540
Subtotal	3,367
TOTAL TEST YEAR PURCHASED ENERGY (GWh)	3,373

Notes:

1. Totals may not add due to rounding.
2. Rounded to nearest GWh. Refer to HECO-504.

Hawaiian Electric Company, Inc.

PURCHASED ENERGY FROM CHEVRON AND TESORO FROM 2001 TO 2005
Annual kWh

	2001	2002	2003	2004	2005	Total	5-Yr Avg
Chevron	341,846	302,435	2,105,228	90,146	104,958	2,944,613	588,923
Tesoro	6,512,832	6,913,588	5,449,573	3,677,119	3,967,680	26,520,792	5,304,158

Hawaiian Electric Company, Inc.

HISTORICAL PURCHASED POWER PRODUCTION
Annual GWh

	2001	2002	2003	2004	2005	2007 Test Year
As-available	14	9	8	4	4	6
Firm Energy	3,141	3,111	3,232	3,205	3,379	3,367
Total	3,155	3,120	3,240	3,208	3,383	3,373

Totals may not add due to rounding.

Hawaiian Electric Company, Inc.

2007 TEST YEAR FIRM ENERGY EXPENSE
($000)

	2005 Actual	2007 Test Year
Kalaeloa- Fuel	115,932	145,372
Additive	1,994	2,374
Non-Fuel	20,749	20,680
Shortfall	0	0
Total	138,675	168,426
AES Hawaii- Fuel	39,428	41,126
O&M	27,078	28,377
Total	66,506	69,503
H-POWER- Energy	26,921	38,730
Other		
Chevron	0	77
Tesoro	387	696
Total	387	773
Total Energy	232,489	277,432

Notes:

1 Totals may not add due to rounding.

2 HECO did not pay Chevron for energy received in 2005 because that energy was used first to offset accumulated substation transformer losses (kWh).

Hawaiian Electric Company, Inc.

2007 TEST YEAR FIRM CAPACITY EXPENSE

	Capacity Payment ($000)	
Firm Capacity Producer	2005 Actual	2007 Test Year
Kalaeloa	30,393	32,719
AES Hawaii	68,942	67,891
H-POWER	6,035	6,877
AES Hawaii bonus	1,407	1,189
TOTAL	106,777	108,676

Notes:

1 Totals may not add due to rounding.

2 For 2005, the H-POWER capacity payment amount is reduced by sanction.

TESTIMONY OF
DAN V. GIOVANNI

MANAGER
OPERATIONS & MAINTENANCE
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Production O&M Expense, Production Inventory

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dan V. Giovanni. My business address is 475 Kamehameha Highway, Pearl City, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Power Supply Operations and Maintenance ("PSO&M") Department at Hawaiian Electric Company ("HECO"). HECO-600 provides my educational background and work experience.

Q. What is your responsibility as a witness in this proceeding?

A. In this proceeding it is my responsibility to present the appropriate Other Production O&M Expense (other than fuel and purchased power), and Production Stores Inventory for test year 2007.

Q. What is the scope of your testimony?

A. In this testimony, I will:

1) summarize Other Production O&M Expense,
2) discuss the HECO generating system, including a discussion on Adequacy of Supply challenges,
3) discuss Production staffing level requirements to operate HECO's generating units and provide a sustainable level of acceptable reliability,
4) discuss critical factors that impact Other Production O&M Expenses,
5) discuss Other Production O&M Expense (other than fuel and purchased power), and
6) discuss Production Stores Inventory for test year 2007.

SUMMARY OF OTHER PRODUCTION O&M EXPENSE

Q. Please provide a summary of HECO's estimate of its 2007 test year Other Production O&M Expense.

A. HECO's 2007 test year estimate for Other Production O&M Expense (after adjustment or normalization) other than fuel and purchase power ("Other Production O&M Expense") is $68,222,000 as shown in HECO-601. Of this total, $29,112,000 is for Other Production Operation Expense and $39,110,000 is for Other Production Maintenance Expense as shown in HECO-601.

Q. What makes up the 2007 test year estimate for other production operations expense?

A. As shown on HECO-602, the 2007 test year estimate for Other Production Operations Expense is $29,112,000. Of this total, $14,242,000 is for labor expense and $14,870,000 is for non-labor expense.

Q. What makes up Other Production Maintenance Expense?

A. As shown on HECO-602, the 2007 test year estimate for Other Production Maintenance Expense is $39,110,000. Of this total, $15,219,000 is for labor expense and $23,891,000 is for non-labor expense.

Q. What is the 2007 test year estimate for production materials inventory?

A. As shown on HECO-603, the year end average estimate for 2007 test year Production Materials Inventory is $6,989,000.

DESCRIPTION OF THE HECO GENERATING SYSTEM

Q. Please describe the electric power generating system and the generating units that supply power to the customers on Oahu.

A. HECO-604 summarizes the primary sources of electric power supplied to Oahu. For the test year, HECO's generating system is comprised of 14 steam-electric units, two combustion turbines, and 18 Distributed Generator (DG) units (three of which are planned to be added in 2007). Of the 14 steam-electric units, eight are "baseload" and operate continuously and six are "cycling" and may be started and stopped each day. The two combustion turbines and DG engines are intended to operate as "peaking" units and are operated only when needed to meet system requirements. There are also three baseload units known as "AES," "Kalaeloa," and "H-Power" that are owned and operated by Independent Power Producers (IPP). HECO-604 shows the respective generating unit capacities, type of unit, intended operating mode, installation date, and age for all the units. All of the generating units in the HECO generating system are staffed with operating personnel on a 24 X 7 basis except for the peaking units.

<u>Dispatch of Generating Units on the HECO System</u>

Q. Please explain how baseload, cycling, and peaking units are dispatched to meet daily customer demand.

A. At any particular time, generating units that are not on outage for scheduled or unscheduled maintenance are designated as "available." Available HECO and IPP generating units described above are typically dispatched to: (1) meet system load requirements; (2) provide adequate spinning reserve (SR) and quick load pickup (QLPU) capability; and (3) provide voltage support throughout the system.

1) <u>Baseload Generating Units</u> are operated 24 hours per day, 7 days per week. Baseload units include Kahe 1 through Kahe 6; Waiau 7 & 8; AES; Kalaeloa CT1, CT2, and Steam Unit; and H-Power.

2) <u>Cycling Units</u> may be started or stopped on a daily basis (within hours), or may operate indefinitely as needed. Cycling units include Honolulu 8 &

9, and Waiau 3 through Waiau 6.

3) Peaking Units include two combustion turbines (Waiau 9 & 10), and the 18 DG engines. These units are quick starting and are primarily intended to support SR and QLPU requirements during brief periods at the highest peak demand period of the day, or to support emergency generation during periods of generation shortfall.

Q. What are the definitions of Spinning Reserve (SR) and Quick Load Pickup (QLPU) in the context of the HECO Generating System?

A. Spinning Reserve (SR) is the sum of the capabilities of all generating units operating on the grid less the system load demand at any point in time. HECO has established a SR operating criterion for its electric system (e.g., as of November 30, 2006, typical SR equals 180 MW). The purpose of HECO's SR operating criterion is to avoid customer disruptions caused by the sudden loss of the largest generating unit operating on the grid. In order to satisfy SR criteria, this SR must be equal to or greater than the capacity of the largest operating unit (e.g., AES, Kahe 5, or Kahe 6). Thus, in the event the largest operating unit trips off line there would still be ample generating capability on line to meet demand, and hopefully, stabilize the grid.

Quick Load Pickup (QLPU) is the combined increase in generation of all generating units that are on line at the time of an unexpected generator forced outage. The amount of load each generator is expected to pick up within three seconds following a forced outage is estimated at 60% of the respective generator's remaining capability. The purpose of having QLPU is to operate the system with sufficient generation reserves to stabilize system frequency immediately following a generating unit forced outage above the point where automatic and/or manual load shedding, or underfrequency trips of baseloaded IPP units, may interrupt customer service. At the point stability is achieved, frequency will no longer continue to sag and will remain stable, but lower than 60 hz. Remaining spinning reserves and the startup of additional standby generation are used to restore system conditions back to 60 hz at nominal voltage.

Q. What is the typical HECO SR criterion?

A. It depends on the largest unit operating on the system at any point in time. For example, when AES is on line, the SR criterion would equal 180 MW. When AES is unavailable, i.e., down for maintenance, the next largest unit is K5 or K6 at 142 MW. (Kalaeloa is considered to be two units, since trip of a single combustion turbine or the steam unit would not result in loss of the facility's entire output.)

Q. What is the relationship between system demand, SR, and QLPU?

A. System demand is the electric energy being consumed by all customers at any point in time ("system demand" and "system load" are used interchangeably depending on the context of the discussion).

The typical daily system demand profile varies over a 24-hour period from a minimum to a peak as shown in HECO-605. Under normal conditions when system supply exactly matches demand, system frequency is at 60 hz and voltages are at nominal levels throughout the transmission (138kv), sub-transmission (46kv), and distribution (≤12kv). On the generation side, the terms "supply" and "generation" are the same and represent the sum of electric power generation from all of the running generating units. If a disturbance occurs, i.e., a generator forced outage, and demand exceeds supply, frequency will sag below 60 Hz. If system frequency is allowed to sag too low, customers will experience interruption of service due to automatic and/or manual load shedding in an attempt to keep the total system from collapsing. Severe under frequency may also cause IPP units to trip due to underfrequency protective relays. In order to minimize interruption of service, additional reserve capacity is factored into the dispatch of generating units in accordance with HECO's SR and QLPU criteria. That is, under normal conditions, additional generation reserves are on line and available to allow recovery from the sudden and unanticipated loss of the largest generating unit and prevent load shedding and the possible loss of IPP generating units due to underfrequency. HECO-606 illustrates the relationship between each generating unit's operating level to support system demand, and the unit's QLPU and SR capability up to its normal top load (NTL). All generating units, with the exception of baseloaded IPPs that normally operate at full load, will have similar relationships between their operating load, QLPU and SR. The composite of all generating unit SR and QLPU capabilities makes up the system SR and QLPU capability, which is normally 180 MW when AES is on line.

Q. Please provide examples where SR and QLPU were employed to avoid an interruption of service to customers and stabilized the grid.

A. There are many examples where SR and QLPU existing on the system have been utilized to compensate for the sudden loss of generation without experiencing a corresponding interruption of service to HECO's customers. Two specific examples were described in HECO's 2006 Adequacy of Supply (AOS) Report (filed with the PUC on March 6, 2006) on the bottom of page 2. In the first example, W10 tripped at 1657 hours on November 8, 2005 while generating 42 MW. Frequency decreased to 59.7 Hz, and as a consequence of SR on the system at the time, there was no load shed. In the second example, K6 tripped at 0730 hours on January 10, 2006 while generating 110 MW. Frequency decreased to 59.3 Hz and, because of the reserve capacity provided by SR, no load was shed.

Reliability of the HECO Generating System

Q. What metrics are used to measure the reliability of HECO's generating system and its individual generating units?

A. HECO uses two metrics to track generating unit reliability: Equivalent Availability Factor ("EAF"), and Equivalent Forced Outage Rate ("EFOR"). Both are standard measures of generating reliability and are regularly compiled and reported to the National Electrical Reliability Council ("NERC").

Q. What does EAF measure?

A. EAF measures the percentage of time that a generating unit, combination of generating units, or the generating system as a whole is available to operate at full capacity. A higher EAF rating indicates better reliability.

Q. What does EFOR measure?

A. EFOR measures the percentage of time that a generating unit, a combination of generating units, or the generating system as a whole is unavailable to operate at full capacity due to unplanned (i.e., "forced") outages and deratings. A lower EFOR rating indicates better reliability.

EFOR is a subset of generating unit availability and accounts for unanticipated shutdowns caused by forced outages and generating unit deratings caused by equipment problems that allow operation of the generating unit, but at a lower level of output. "Forced Outages" are unplanned unit shutdown caused by a number of factors, e.g., automatic or programmed protective trips, operator-initiated trips due to equipment malfunction or maintaining compliance with established permits, or operator error. "Forced Deratings" are unplanned unit events caused by equipment malfunction or deterioration such that full load cannot be achieved. (For example, a generating unit that can only produce 78 MW of its 90 MW normal capacity is considered derated.) An example of a generating unit derating's impact on EFOR is if a unit is limited to 90% of full power because of an equipment malfunction, its EFOR would be 10% for the duration of the derating.

Q. How does HECO's Generating System EAF and EFOR compare with NERC statistics for other generating systems?

A. HECO has been measuring itself to the utility industry for many years and has provided these comparisons in prior rate cases. In 2006, HECO also commissioned EPRI Solutions, Inc. (ESI) to perform a review of HECO's Power Supply operations, maintenance and outage management programs. The review report, entitled *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs"* was filed with the Commission on October 20, 2006. HECO-607, the letter transmitting the report to the Commission, provides a summary of the report's main points.

Q. What does ESI conclude related to HECO's EAF and EFOR performance?

A. ESI's conclusion, stated on page 32 of the report, is "ESI observed that, over the past two (2) decades the HECO steam fleet has performed exceptionally well compared to industry averages in both of these categories." The report does note, however, on page 33 and 34, a trend of decreasing availability and reliability within the past five years, up to 2005.

Q. What has been HECO's EAF and EFOR performance in 2006?

A. HECO has tracked its EAF and EFOR performance in 2006 on a daily basis. The year-to-date results, as of November 30, 2006, are EAF at 86.74% and EFOR at 5.39%. These reliability measurements are an improvement over the 2005 year-end EAF of 84.54% and EFOR of 9.25%.

Q. How has HECO's EAF and EFOR performance in 2006 compared to that for recent years?

A. As summarized below, HECO's 2006 EAF and EFOR (as of November 30, 2006) have improved.

	2004	2005	2006
EAF (%)	85.84	84.54	86.74
EFOR (%)	6.16	9.25	5.39

Q. How does HECO's 2006 EFOR performance in 2006 compare to the Forward Looking EFOR projection in the HECO's 2006 Adequacy of Supply (AOS) Report filed with the PUC on March 6, 2006?

A. As discussed in the HECO's 2006 AOS Report: "Based on HECO's maintenance experience in 2004 and 2005, lower generating unit availabilities and higher EFOR estimates are expected to continue in the near future." The 2006 AOS projected the "Forward-Looking EFOR to be 6.8%. Hence, HECO's 2006 EFOR (as of November 30, 2006) performance of 5.39% is better than projected and represents a turnaround from the higher level experienced in 2005.

Q. Was the 2006 AOS Forward Looking EFOR projection of 6.8% reasonable?

A. Yes. As stated in the 2006 AOS: "This higher EFOR projection (compared to the 2005 AOS projection) reflects an expectation of continued constraints on maintenance flexibility, continued aging of the generating units, anticipation of more catastrophic forced outage events and deratings resulting from the cycling operation of certain units and their auxiliary equipment, and more frequent and longer duration overhauls and maintenance outages."

Unplanned deratings and/or unit trips are difficult to predict, and are related to how hard HECO's aging units are operated, and the amount of reserve margin available to perform repairs while minimizing risk to the system. When problems are detected, corrective action is taken as soon as possible once the root cause is identified. In the case of unplanned deratings, corrective action may be delayed depending on expected system demand, available reserve margin, outage priorities on other units, and parts/materials availability.

Q. How does EFOR contribute to the reserve margin shortfall situation that HECO is currently facing?

A. As explained in HECO's 2006 AOS Report, HECO's capacity planning criteria are applied to determine the adequacy of supply and whether or not there is enough generating capacity on the system. HECO's capacity planning criteria consist of two rules and one reliability guideline. The reserve capacity shortfalls calculated in the AOS Reports are determined by the application of the reliability guideline, which involves a Loss of Load Probability ("LOLP") calculation. The outputs of the LOLP calculation are driven by the input assumptions. The key input assumptions include the load to be served, the amount of firm capacity on the system, and the availabilities of the generating units. The EFOR of a generating unit is one of the key determinants of the availability of the unit. As EFORs increase, the amount of reserve margin necessary to satisfy the reliability guideline also increases.

Q. What steps is HECO taking to address the reserve margin shortfall situation?

A. These are addressed in Mr. Sakuda's testimony, HECO T-4. From a Production O&M perspective, the Action Plan and Mitigation Measures includes (but were not limited to):

- Sustaining an operational staff to allow for 24 hours a day, 7 days a week operation of all steam generating units,
- Pursuing the staffing plan for night maintenance of HECO's generating units,
- Pursuing initiatives that improve EFOR for HECO generating units, and
- Evaluating additional DG opportunities.

Each of these measures is included in the Other Production O&M Expense and will be discussed in my testimony.

Q. Is capacity reserve margin more of a concern for an island utility like HECO as compared to a mainland utility?

A. Yes. On the mainland, utilities are interconnected to neighboring utility systems and can rely on this large, interconnected power grid for reserve capacity and system stability. An island utility such as HECO must coordinate the operation and maintain all of the generating units directly connected to its "isolated" grid, including those of the IPPs, such that there is sufficient generating capacity at all times to meet system requirements, including SR and QLPU criteria.

Q. How do the current demands upon the HECO Generating System affect O&M requirements?

A. In general, the current demands upon the HECO Generating System impact O&M requirements in two ways: (1) all of HECO's units have to be available for 24 X 7 operation except during periods of planned and unplanned maintenance; and (2) adequate amounts of preventative and corrective maintenance must be performed on a continuing basis to sustain the reliability of HECO's generating units at acceptable levels.

Q. How is the Other Production O&M Labor expense impacted by these requirements?

A. The Other Production O&M Labor expense is impacted by these requirements in two ways: (1) larger staff to operate all of HECO's baseload and cycling units on a 24 X 7 basis; and (2) more personnel to perform maintenance needed to sustain the reliability of HECO's aging generating units at a level to meet system requirements throughout the year. Staffing details will be covered separately in my testimony, as will the Other Production Operations Labor expense and Other Production Maintenance Labor expense.

Q. How is the Other Production O&M Non-labor expense impacted by these requirements?

A. The Other Production O&M Non-labor expense is impacted by the need for more frequent and more extensive repairs as HECO's aging equipment experiences increased wear and tear. This additional work is manifested many ways, including repair/replacement of small and medium equipment components (e.g., transducers, valves, breakers, motors, pumps, controllers,), upgrading of critical power plant infrastructure (e.g., power and control cables, underground and above ground piping, cooling water intake structures), and overhauls of major equipment (e.g., boilers, turbines, generators, condensers, boiler feed pumps, circulating water pumps) at regular intervals. These increased expenses are discussed in greater detail later in my testimony.

Age and Operation of HECO's Generating Units

Q. Please describe the age of the generating units and related infrastructure in the

HECO system.

A. As shown in HECO-604, the average age of HECO's six cycling steam units and eight baseload steam units are 51.3 years and 36.3 years, respectively. HECO's two peaking combustion turbines, Waiau 9 and 10, are 33 years of age. The IPP facilities, H-Power, Kalaeloa and AES are 16, 15, and 14 years of age, respectively. Regarding infrastructure, some of the Waiau Power Plant infrastructure still in use today dates back to 1938. The Honolulu Power Plant infrastructure dates back to 1930.

Q. How are these aging generating assets benefiting the ratepayer?

A. Although the generating units are aging, application of chosen technologies and process improvements benefit the ratepayer by avoiding the need to replace existing generating capacity. Relative to mainland counterparts, HECO units continue to operate with a relatively high degree of reliability. Maintaining our existing units remains the least cost option even though it will increase HECO's Other Production O&M Expense.

Q. Please discuss how unit age impacts Other Production O&M Expenses.

A. In the electric power industry, fossil fuel generating units are typically designed for a useful life of approximately 30 years. Due to a variety of factors, many utilities have found that it is economically advantageous to continue to operate and maintain these units beyond their 30-year design life. By performing the requisite maintenance on a consistent basis it may be possible to operate these units indefinitely. However, as the units become older and operating duties become more severe (e.g., increased cycling duty), the maintenance required to sustain acceptable levels of performance becomes more costly.

As stated in the 2006 AOS, Appendix 7, the major factors contributing to EFOR include unit and equipment age (older units tend to have higher EFOR than newer units), operating duty (i.e., minimum load, on/off cycling, etc.), human factors, compliance with environmental restrictions, and safety. The severity of unit operating duty (running units harder) increases as the units age, because the older units, over time, become less efficient than the newer units.

In addition, generating units are made up of very complex systems and equipment that wear and tear at different rates as they age. Older mechanical and electrical equipment are prone to break down more frequently than newer equipment. Oftentimes, imminent breakdowns cannot be detected despite best efforts to regularly inspect and maintain the equipment. Also, acquiring replacement parts on older equipment become more challenging due to obsolescence, and substitute parts that are often reengineered by other than the original equipment manufacturer (OEM) require several iterations to refine the design. This can increase the amount of time a unit remains out of service.

Q. Please explain what you mean by change in operating duty.

A. The new units in a particular class, i.e., non-reheat steam units, started out as base loaded units when they were first placed on line, because they tended to be the largest and most efficient. Over time, newer, larger and more efficient units (i.e., reheat steam units) were added to the HECO system, and were baseloaded, leaving the relatively less efficient non-reheat units to cycle. As a consequence of shifting mode of operation from baseload when they were new (least severe on equipment), to cycling when they were older (most severe on equipment), wear and tear on equipment increased as the units got older. These steam units were originally designed to operate in baseload duty, and were <u>not</u> designed to withstand the stresses of daily starting and stopping. However, as the larger, more efficient units came into service and were placed into baseload duty, the smaller, less efficient units were placed into cycling duty to support the daily changes in peak loads. (The cycling units include Waiau Units 3 to 6 and Honolulu Units 8 and 9.)

HECO baseloaded reheat steam units are also being affected by the impact of daily minimum loads on their respective auxiliary equipment. (HECO's baseload units include Kahe Units 1 to 6 and Waiau Units 7 and 8.) The cause is attributed to the addition of IPP baseloaded capacity in the early 1990's that required HECO baseload units to share the minimum load with IPP baseload units. Due to the relative differences in efficiency between the HECO reheat units and the IPP units, HECO baseload units are operated down to their respective minimum loads to meet system requirements while IPP baseloaded units operate close to their maximum output. In order to operate safely at minimum loads, HECO baseload units must cycle (on/off operation) critical auxiliaries on a daily basis. This mode of operation increases the wear and tear on critical auxiliaries and increases the potential for breakdown and subsequent operation with a derating.

Another contributing factor to the stress placed on the units is the increasing number of hours that HECO's cycling and peaking units are running as system demand grows. The cycling and peaking units and their associated auxiliary equipment must turn on and off, on a daily basis, and this results in cyclic thermal stresses and accelerated wear on cycled auxiliary equipment, which damage critical parts, and can result in a generating unit forced outage or derating. The increased operating hours add to the stress on the units.

HECO's peaking units were designed to start and stop daily and operate only a few hours a day to serve the peak demand period, which occurs usually between the hours of 5:00 pm to 9:00 pm. (HECO's peaking units are Waiau Units 9 and 10, which are combustion turbines.) From 1993 to the late 1990s when HECO enjoyed a higher reserve margin, the peaking units generally operated between 100 and 200 hours each per year, which is typical for peaking units. In recent years, they have been averaging over 1,000 hours each per year. This operation is more like cycling duty, and the longer operating hours are increasing the "wear and tear" on these units. In 2004, Waiau Unit 9 experienced a forced outage of long duration resulting from the catastrophic failure of some of its compressor blades.

Maintenance of HECO's Generating Units

Q. How is HECO managing the effects of its aging equipment to sustain acceptable levels of performance?

A. HECO is managing the effects of its aging equipment through a comprehensive maintenance program that includes planned and unplanned work. The majority of maintenance work is performed during a unit outage, when the unit is taken off line. Maintenance work that requires an outage to perform falls into one of three categories:

1) Planned Outages (PO), or "overhauls," are time driven and may be planned years in advance. For any given year, the POs of individual units are scheduled so that estimated system load demand, spinning reserve, and quick load pick up criteria are continuously satisfied. In general, each of HECO's baseload and cycling generating units is overhauled every three years. Every overhaul generally includes a major boiler inspection and

repair/replacement of selected boiler components. Every six years, or every other overhaul, a major inspection of the turbine is included. Every third overhaul includes major inspection and work on the generator and major electrical gear. The schedules for overhauls of HECO's two combustion turbine, Waiau 9 and 10, the peaking units, are primarily based on projected service hours. The durations of all overhauls generally range from four to twelve weeks depending on the scope of the overhaul and associated capital projects that are scheduled coincidently. In addition to the major inspections identified above, the scope of work during an overhaul normally includes maintenance on the backlog work orders that require a unit outage, capital projects, preventative maintenance in accordance with manufacturer's recommendations, and metallurgical assessments. The 2007 test year Planned Maintenance Schedule shown in HECO-608 generally represents a normal overhaul year, where generating units are selected based on the criteria mentioned above, and are planned and forecasted accordingly.

2) Maintenance Outages (MO) may be planned days to months in advance. The duration of a MO may range from a several hours to a few weeks. MOs are planned and scheduled when system conditions allow the loss of generating capacity throughout the outage, that is, when spinning reserve and quick load pickup criteria can be met while maintenance work is in progress. MOs do not require an immediate shutdown of the unit. In many instances, however, delaying the MO could worsen the unit condition (i.e., thermal performance may deteriorate and cost for maintenance repairs may increase) if not scheduled on a timely basis.

The scope of work during a MO normally includes correction/repair of the problems justifying the MO, maintenance on the backlog work orders that require a unit outage, and preventative maintenance. The 2007 test year Planned Maintenance Schedule shown in HECO-608 also includes nominal MOs for units that are not scheduled to have an overhaul during 2007.

3) Forced Outages (FO) are immediate, unplanned outages where the unit is either automatically (i.e., protective relay trip) or manually (i.e., operator initiated) shutdown depending on the nature of the problem. FOs are costly events because they generally result in a diversion of maintenance resources, procurement of materials and outside services on an expedited basis, operation of less efficient cycling and peaking units, and in the worst case, generation shortfalls and the interruption of service to customers.

Q. What maintenance work is performed when the unit is on line?

A. "Operational Maintenance" is performed when the generating unit is on line and does not require a PO, MO or FO.

Q. Can Maintenance Outages (MO) be planned far in advance with certainty?

A. No. MOs are generally scheduled to perform necessary repairs on critical equipment (e.g., pumps, motors, fans, breakers, boiler tubes, boiler casing, etc.) that fails in service, requires an outage to make the repairs, and a Forced Outage (FO) is unnecessary (i.e., the unit can continue to operate in a deteriorated or impaired state). It is not possible to predict when equipment will fail with any certainty. Power plants are made up of thousands of pieces of equipment, controls and infrastructure, and every component that makes up a power plant wears and/or fails at a different rate. Accordingly, for any given year there are several MOs that can not be anticipated far in advance that are added to the Planned Maintenance Schedule. To illustrate this point, HECO-609 and HECO-610 show the actual versus Planned Maintenance Schedules for 2005 and 2006 year-to-date (September 2006), respectively. The actual schedules include the MOs that could not be predicted when the schedule was originally constructed.

Q. Please explain the MOs that are shown in the 2007 Planned Maintenance Schedule, which are planned far in advance.

A. For those units that are not scheduled for an overhaul in 2007, MOs are being planned to perform work that can be anticipated, such as air preheater cleaning to circulating water tunnel cleaning, boiler water washing, and annual preventative maintenance in accordance with manufacturer's recommendations.

Q. The schedules included in HECO-609 and HECO-610 show significant changes in the POs, as well as the MOs, as the year progresses. Please explain why this occurs.

A. The scheduling of planned overhaul and maintenance outages is very dynamic in nature. When forced outages occur, or potential problems are discovered such that an outage is needed to address it, the outage schedule must be rearranged. The dynamic nature of scheduling outages was discussed in HECO's 2005 Test Year Rate Case.

Moreover, as generation reserve margins shrink, maintenance scheduling flexibility becomes more difficult. In addition, as the generating units age, they generally need to be maintained more often and for longer periods of time. Finally, as the demand for electricity increases, the generating units operate harder, which increases the likelihood of unscheduled (forced) outages and operations at derated power levels. Generating units that were shutdown unexpectedly generally require immediate maintenance. As resources are shifted to make the emergency repairs, maintenance outage schedules slip, making maintenance scheduling flexibility even more difficult. In addition, generating units operating in a derated capacity cannot be afforded the luxury of a maintenance shutdown to restore the unit to full power operations. These units are generally operated for long periods in a derated state.

To further illustrate how the Planned Maintenance Schedules change with time note that the 2007 Planned Maintenance Schedule dated February 14, 2006 (HECO-608) was issued and utilized, in part, to develop the 2007 budget expenses. The 2007 Planned Maintenance Schedule was revised and issued July 21, 2006 (HECO-611). This version was used as the basis for the Production Simulation Model calculations performed for the 2007 rate case filing, and for revisions to the 2007 estimate for Other Production O&M Expense. Refer to the testimony of Mr. Ross Sakuda (HECO T-4) that describes the Production Simulation Model calculations. The 2007 Planned Maintenance Schedule was revised and issued November 21, 2006 (HECO-612) to adjust for the Kahe 1 and Honolulu 9 overhauls extending longer into 2007 than anticipated and necessitating the rescheduling of other overhauls so that the SR criterion is satisfied throughout the year.

Q. Describe the different types of maintenance work that are generally performed.

A. HECO generally performs the following types of maintenance:

1) Preventative Maintenance (PM). PM is generally performed on a scheduled basis to prevent equipment failure while in service and to sustain equipment performance in accordance with design specifications.

PM would include items such as replacement of fluid and gas filters, changing lubricating fluids, replacement of wear components in moving equipment, periodic greasing of traveling screen chains and soot blower drives, and boiler tube cleaning (internal and external).

2) Corrective Maintenance (CM). CM is generally performed to repair or replace equipment that has failed in service or whose performance has deteriorated by a significant degree. Types of CM may include: rebuilding or replacement of large pumps, motors, regulators, valves; repair or replacement and turbine-generator bearings and rebalancing of the rotor; and repair or replacement of failed boiler tube sections.

3) Predictive Maintenance (PdM). PdM is implemented based on the assessed condition of equipment and in order to prevent equipment failure while it's in service. Equipment condition is assessed utilizing techniques that monitor and analyze specific operating parameters. PdM measurement techniques include vibration analysis of rotating equipment, chemical analysis of lubrication and hydraulic fluids, ultrasonic analysis, on-line infrared thermography, and pump pressure-flow performance tests. State-of-the-art instruments and software are used to monitor and track the condition of critical equipment. PdM work may be comprised of PM or CM type work. For example, a generating unit that has multiple pump-motor sets (e.g., boiler feed pumps, circulating water pumps, condensate pumps) will have a PdM assessment of each. Then, based on the PdM results CM maintenance would be performed on the pump-motor set(s) that are in the poorest condition and prone to failure.

Q. Do all types of maintenance work require an outage?

A. No. In many cases the equipment requiring maintenance may be safely isolated and Operational Maintenance may be implemented without an outage. In other cases a derating of the unit or an outage will be required while the maintenance work will be performed. For example, if a boiler feed pump needs to be repaired it is typical that the work may be performed while the unit is derated. A HECO unit typically has two boiler feed pumps and the unit may be operated at approximately half its capability on the "good" boiler feed pump, while the "bad" boiler feed pump is isolated for repair. In this case the unit would be derated to approximately half capability until the second boiler feed pump was repaired and returned to service.

Q. When is Operational Maintenance performed?

A. Operational Maintenance is performed on a daily basis while the units are operating. Operational Maintenance is typically scheduled days or weeks in advance.

Q. Has HECO taken steps to improve its maintenance practices?

A. Over the years HECO has studied the application of various technologies and testing techniques, and implemented targeted maintenance programs to improve the reliability of its generating units. The studies and programs primarily focus on critical pieces of equipment such as the boiler, generator and turbine that significantly impact unit availability. For example HECO pioneered turbine cylinder crack repair procedures on Honolulu Units 8 & 9, in 2002 and 2003, with a high degree of success by combining selected non-destructive testing techniques with in-house expertise to avoid purchasing long lead (up to two years) replacement turbine cylinders. From that time to date no problems attributed to turbine cylinder cracks have been experienced. Further elaboration on other examples was provided in HECO's response to CA-IR-439 in HECO's 2005 Test Year Rate Case (Docket No. 04-0113).

In addition to HECO's internal continuous improvement efforts, and as noted earlier in this testimony, HECO retained consultants from EPRI Solutions to review HECO's operating, maintenance and outage practices, processes, and policies to look for untapped opportunities to improve its generation assets' availability and reliability. This review and evaluation included the following actions:

- Review studies, recommendations, reports and other documents related to generating unit maintenance practices.
- Evaluate unit-specific and system EFOR/EAF trends and events.
- Review HECO maintenance capabilities, limitations, and opportunities as they relate to HECO's generating units.

HECO selected EPRI Solutions because HECO has, in the past, benefited from the expertise of the Electric Power Research Institute ("EPRI") on improving the reliability of its generating units. One example is the design of HECO's Boiler Reliability Optimization program, started in late 1998, and finalized in November 2001, with the issuing of a Boiler Reliability Optimization Procedures Manual. The effectiveness of the program has resulted in reducing forced outages caused by boiler tube leaks from a high of 59 forced outages in 1999 to a manageable seven to eleven forced outages between 2001 to 2005, and has elevated HECO's industry ranking to "world class" status. Further elaboration was provided in HECO's response to CA-IR-50 in HECO's 2005 Test Year Rate Case.

In the late 1990s and early 2000s, HECO also developed a Power Supply Reliability Optimization (PSRO) Program under the guidance of EPRI Solutions. The goal of this program is to cost-effectively increase the availability and reliability of the generating units by combining established industry maintenance practices and philosophies, i.e., predictive maintenance, preventive maintenance, corrective maintenance, and proactive maintenance, with state-of-the-art technologies, effective analysis techniques, and information management systems. The effectiveness of the program depends heavily on the ability to schedule the various types of maintenance – Predictive Maintenance, Preventive Maintenance, Corrective Maintenance, and Proactive Maintenance. To this end, adequate reserve capacity and scheduling flexibility are required to optimize maintenance while mitigating risks.

Q. How is HECO's PSO&M Department organized to perform its maintenance work?

A. The PSO&M Department maintenance workforce is organized into several groups to perform its maintenance work as follows: "Station Maintenance Crews" permanently deployed to Kahe, Waiau, and Honolulu Power Plants, respectively, and a "Travel Maintenance Crew" that performs maintenance at all three power plants. In general, the Travel Maintenance Crews perform major PM and CM during each of the overhauls, and CM on major equipment (e.g., steam turbine, generator, boiler). The Station Maintenance Crews perform PM and CM on a day-to-day basis at their respective power plant throughout the year. In addition, as needed to perform the required work, the Travel and Station Maintenance Crews will be supplemented using contracted services.

Also, as discussed next, we have taken and are continuing to take aggressive steps to add maintenance staff, and have reorganized the PSO&M Department.

Q. What steps need to be taken to sustain and further the improvement in EFOR achieved in 2006?

A. Restoring the reserve margin by adding generation (as addressed in Docket No. 05-0145) and managing load (as addressed in the Energy Efficiency and Load Management dockets) will help, by providing HECO with more flexibility to schedule and perform maintenance on our aging generation assets.

Just as importantly, we need to be able to carry out our staffing and training plans, so that we will have the staffing assets necessary to effectively perform the reliability programs and initiatives discussed in our 2005 rate case testimonies and information responses and in the 2006 ESI study.

PRODUCTION STAFFING

Q. What category of Other Production O&M Expense represents the largest increase between the 2005 actual expense and 2007 test year estimated expense?

A. Other Production O&M Labor expenses represents the largest difference between the 2005 actual expense and 2007 test year estimated expense as follows:

	2005 Actual	2007 TY Estimate	Change	% Change
Labor	$22,823,000	$29,461,000	$6,638,000	29.1%
Non Labor	$34,305,000	$38,761,000	$4,456,000	13.0%
Total	$57,128,000	$68,222,000	$11,094,000	19.4%

(Source: HECO-WP-101A, page 2, and HECO-602.)

Q. What are the major factors that contribute to this labor expense increase between 2005 and 2007?

A. The expense increase is primarily attributable to two factors: (1) growth in the HECO Power Supply O&M ("PSO&M") staff by approximately 15%, and (2) increased direct and indirect labor costs per employee.

Q. Please describe the past, current, and forecast staffing levels.

A. The HECO Power Supply Process Area is comprised of the following: Environmental Department, Power Supply Engineering Department, Power Supply PSO&M Department, Power Supply Services Department, and VP-Power Supply's Office. HECO-613 summarizes the employee counts for each department in the Power Supply Process Area from 2004 to the 2007 test year estimate.

Q. How is the total staffing level expected to change for the Power Supply Process Area?

A. As shown in HECO-613, the staffing level for the Power Supply Process Area was 394 at the end of 2005, and is forecast to increase from an actual staffing level of 396 as of September 30, 2006 to 407 at 2006 year end, and to 455 in test year 2007. Hence, the change in staffing level from the end of 2005 to 2007 is expected to be 61.

Q. How will the increase of 61 employees between the end of 2005 and 2007 be distributed among the departments in the Power Supply Process Area?

A. The distribution of the increase is summarized below:

	2005 Recorded	2007 TY	Difference
Environmental Dept.	22	24	2
Power Supply Engineering Dept.	41	46	5
Power Supply O&M Dept.	299	352	53
Power Supply Services Dept.	30	31	1

VP-Power Supply's Office	2	2	0
TOTAL	394	455	61

HECO-614 provides descriptions for each position in the Power Supply Process Area and shows the estimated hire date for each of the vacant positions that will be filled by 2006 year end and in the 2007 test year.

Q. Does the 2007 test year estimate for Other Production O&M expense assume that all positions are filled January 1, 2007?

A. Yes.

Q. Why weren't more adjustments made to the 2007 test year O&M expenses to reflect the fact that a significant number of positions would not be filled a the beginning of 2007?

A. In September 2006, it was evident that a significant number of positions included in the 2007 test year estimate for the PSO&M Department would be vacant for at least some portion of 2007. An analysis was performed at that time to determine if an adjustment to the 2007 test year O&M expenses was warranted. The analysis concluded that an adjustment was not necessary. In the analysis, each position vacancy that would not be filled by the January 1, 2007 was identified. For each, the hire date was estimated and then the means for performing the work anticipated for the vacant position was projected. The anticipated work would be performed by other employees in the PSO&M Department working overtime, by the hiring of consultants or contract employees, or a combination of the two. The additional expense for performing the required work by these alternate means for each vacant position was estimated, the savings in direct labor expenses for the filling the vacancy after January 1, 2007 was estimated, and the difference was determined to be the net expense for not filling each vacant position on January 1, 2007. The sum of the net expenses for all the vacant positions was found to be a positive expense. If it had been a negative expense it may have warranted an adjustment to the 2007 test year O&M expense.

For PS Engineering, PS Environmental, and PS Services Departments the analysis was more qualitative. As discussed below in my testimony the vacant positions in each of these departments are expected to be filled in early 2007, and during the interim the required work will be performed by employees working overtime (uncompensated), consultants, and/or contractors, or the work will be deferred.

Power Supply Environmental Department

Q. Please describe the increase of two in Environmental Department for 2007.

A. The two additional positions in the Environmental Department are:

- Air Quality/Noise Division Sr. Environmental Scientist
- Water/Hazardous Materials Division Environmental Scientist

Q. Why is the Air Quality/Noise Division Sr. Scientist needed?

A. The Air Quality/Noise Division Sr. Environmental Scientist is needed to fulfill changing federal/state permitting and compliance requirements in the area of air quality/noise. This position was vacated in September 2005 and would represent a backfill in 2007.

Q. How has the workload been managed while this position has been vacant?

A. The Air & Noise Division has since managed the workload by several interim measures including: (1) use of outside consultants; (2) absorbing the work within the remaining Senior Scientists; and (3) having the Supervisor for the

Division take on additional assignments that would otherwise be handled by the Senior Scientists.

Q. How has the use of outside consultants impacted the workload?

A. Outside consultants have provided assistance by providing services for some of the work which had previously been accomplished internally. However, because these consultants still require their contracts to be managed and their work products reviewed, it is not a straight one for one tradeoff.

Q. What has been the impact of requiring the work to be absorbed by the remaining Senior Scientists in the Division?

A. Doing so has resulted in requirement of uncompensated additional hours and has reduced their ability to take on new assignments as well as limiting the important services they currently provide to our Operating Departments.

Q. What is the impact of having the Supervisor for the Air & Noise Division absorb some of the extra workload?

A. The impact of the above is that the Supervisor, a Principal Scientist, is performing assignments in permitting and compliance management that would otherwise normally be handled by the Senior Scientists. It has also impacted his ability to develop and take on new assignments.

Q. Why is the Water/Hazardous Materials (Water/HazMat) Division Environmental Scientist position needed?

A. The Water/HazMat Environmental Scientist is needed to fulfill changing federal/state permitting and compliance requirements in the area of water and hazardous materials regulations.

Q. When was this Scientist position last filled?

A. This position was last filled in August 2006 but was converted to a Senior Scientist position to address the increase in Division workload. The Scientist position has not been filled since then.

Q. How has the workload been managed without the Scientist position?

A. The increasing workload has been managed by: (1) use of outside consultants; (2) redistribution of work assignments among existing Water/HazMat Senior Scientists; and (3) having the Senior Scientist continue to absorb many of the duties held while a Scientist.

Q. How has the use of outside consultants impacted the workload?

A. Outside consultants have provided assistance by providing services for some of the work which had previously been accomplished internally. However, because these consultants still require their contracts to be managed and their work products reviewed, it is not a straight one for one tradeoff.

Q. What impact has redistribution of the increased workload had on the Senior Scientists in the Division?

A. Doing so has resulted in requirement of uncompensated additional hours and has reduced their ability to take on new assignments as well as limiting the important services they currently provide to our Operating Departments. In addition, it has the impact of requiring a Senior Scientist to continue to perform Scientist level duties.

<u>Power Supply Engineering Department</u>

Q. Please describe the increase of five positions in Power Supply Engineering Department in test year 2007 versus the actual staff level at the end of 2005.

A. The five existing positions consists of one Senior Staff Controls Engineer position in the Technical Services Division, two Engineer II positions in the

Electrical Engineering Section and two Engineer II positions in the Mechanical Engineering Section.

Q. Why are these five additional positions needed?

A. Following are the reasons that the five additional positions are needed:

- Senior Staff (Controls) Engineer position is needed to support the increasing workload required to implement the new controls upgrade projects and maintain the increasing number of microprocessor based systems.
- Four Engineer II positions for the Electrical and Mechanical Engineering Sections are needed to support HECO's capital improvement program, the O&M program for HECO's existing generating units and the production departments at HELCO & MECO.

Q. What was the staffing level in the Power Supply Engineering Department in 2005?

A. In 2005, the employee count ranged from a low of 39 in February 2005 to a high of 45 in May 2005 and ended the year at 41.

Q. What was the staffing level in the Power Supply Engineering Department in 2006?

A. In 2006, the employee count started at 41 in January 2006, steadily decreased to a low of 35 in October, 2006 due to retirements and resignations, and, as of November 20, 2006, was 40 due to recent hirings. The resignations were primarily due to engineers leaving for higher paying jobs at other companies. Power Supply Engineering Department expects to be at a staffing level of 40 at the end of 2006.

Q. What is HECO doing to stem the loss of engineers?

A. The Hawaii market for engineers has tightened and salary compensation levels for engineers has increased. HECO was unable to match the compensation offered to some of our existing engineers by other firms (as well as to engineer new hire candidates). To address this, HECO recently implemented a targeted compensation program whose objective is to recruit and retain those in critical utility engineering positions. The program takes a two prong approach which includes 1) increasing the market rate for positions with high turnover experience and/or which are difficult to fill, and 2) awarding salary adjustments to key engineers. The first prong allows HECO to use a market rate more current to today's labor market for engineering skills, enabling more competitive salary offers and providing incumbents the opportunity for salary growth within the position. The second prong reduces the risk of losing key engineers who may be critical to a project or critical because of their particular skills/expertise.

Q. What did HECO do to compensate for the reduced level of staffing in 2006?

A. Due to the reduced level of staffing in 2006, some work was contracted to outside consultants. Also, based on an ongoing and iterative prioritization process, lower priority projects were deferred. This is reflected by a decrease in the overall Power Supply capital expenditure spending in 2006.

Q. With a 2007 test year estimate staffing level at 46, when will the remaining six positions be filled?

A. In 2007, Power Supply Engineering Department is forecasting to fill the remaining six positions in the first quarter of 2007. See HECO-614 for filling of staffing positions.

Q. What are the short-term and long-term effects of these vacancies in the Power Supply Engineering Department?

A. The short-term effects of these vacancies has been and will be that work will to be contracted and projects will continue to be prioritized with some lower priority projects being deferred. With the forecasted filling of the remaining six positions in the first quarter of 2007, there are no long term effects anticipated.

Power Supply Services Department

Q. Please describe the changes in the Power Supply Services Department staff level between the end of 2005 and 2007.

A. Actual staff count at December 31, 2005, was 30. The actual staffing level at the end of 2006 is projected to be 28. Budgeted staff count in 2007 is 31. The result is a net increase of one position between the end of 2005 and 2007. HECO anticipates that all the vacancies in the Power Supply Services Department will be filled by February, 2007. See HECO-614 for detail list of positions.

Q. What constitutes the net increase of one position?

A. The net increase of one position between the end of 2005 and 2007 is comprised of the following position changes:

Inc/(Dec)	Position Title	PSSD Division
(1)	Forecast Planning Analyst	Fuels Resources
2	Fuels Contracts Administrator	Fuels Resources
1	Transmission Planning Engineer	Transmission Planning
(1)	Contracts Administrator	PSSD Admin
1	Net Increase	

Q. Please describe the noted position changes in the Fuels Resources Division.

A. In November, 2006, the Forecast Planning Analyst position in the Fuels Resources Division became vacant following the employee holding that position being selected for and transferring to the position of Senior Resource Planning Analyst in the IRP Division at HECO. As a result of this transfer, efforts to back-fill this vacancy were immediately initiated. Upon assessing the evolving business needs and overall responsibilities of the Fuels Resources Division, it was determined that the Forecast Planning Analyst position be replaced by a Fuels Contracts Administrator position, a position with a broader spectrum of functional responsibility and experience. In addition, an effort to recruit and fill one additional Fuels Contracts Administrator position was initiated at the same time. It is projected that the two vacant Fuels Contracts Administrator positions will be staffed by February, 2007.

Q. Please describe the need for the staffing increase of one position in the Fuels Resources Division.

A. The one additional Fuels Contracts Administrator is a new position and an addition to the December 31, 2005 staffing count. The successful management of fuel supply and operations, the efficient administration of the complex commercial and contractual processes, and the effective supervision of distribution facility and transportation services for the procurement and control of the fuel supplies for HECO, HELCO and MECO are necessary for responsible, reliable and safe generation of electric power. The Fuels Division continues to experience and projects further increase in work load due to numerous factors, among which include:

1) Procuring and managing the delivery and storage of new fuel types for future and existing generating units (e.g. biodiesel, ethanol);

2) Increased difficulty and associated time commitment to scheduling inter-island fuel delivery voyage plans due to heightened congestion of harbor facilities state-wide;

3) The expanded operating scope of both the Barbers Point and Iwilei tank farms fuel distribution facilities and the required planning and oversight of a high volume of tanker truck fuel transfers; and

4) The expansion of substation-sited distributed generation necessitating the management of safe and timely fuel procurement and delivery to numerous locations, service contractor retention and oversight, and related administration and accounting.

This addition of staff also supports the key strategic business objective of building adequate staffing within the thinly staffed, highly specialized, and critical Operations Division of the Power Supply Services Department. The staff addition will also provide a platform for succession planning for division leadership. The Fuels Contracts Administrator position vacancies have been posted internally and advertised externally. Interest in the positions has been strong and we presently have a solid list of candidates for interviews. We anticipate completing the interview process, extending job offers to the leading candidates, and filling the vacancies by February, 2007.

Q. Please describe the Transmission Planning Engineer position.

A. The Transmission Planning Engineer is a back-fill position that was vacant on December 31, 2005. This existing position was filled in November, 2006.

Q. What was the staffing situation in the Transmission Planning Division in 2006?

A. First, the Transmission Planning Engineer position became vacant in July, 2005, following the internal transfer of a Lead Transmission Planning Engineer to

System Operations Department, and the promotion of a Transmission Planning Engineer to the Lead Transmission Planning Engineer position. This Transmission Planning Engineer vacancy was initially advertised in August, 2005, however, response to the vacancy was very limited and no viable candidates were identified in that effort.

Q. What was the impact of this Transmission Planning Engineer vacancy?

A. While this position remained vacant, it was a continuing struggle to meet work demands with the reduced resources, particularly as the Transmission Planning Division lost significant technical expertise when the most experienced transmission planner in the division at that time (with intimate knowledge of the HECO system in particular) transferred to operations.

The Transmission Planning Division test year estimate identifies three Lead Transmission Planning Engineers, each with the primary responsibility for planning the respective HECO, HELCO, and MECO transmission systems. In addition, the test year estimate includes four Transmission Planning Engineer positions to provide the necessary engineering support under the guidance of the division Director and lead engineers, with one of these four positions remaining vacant until efforts were again initiated to fill the position in August, 2006. During that time the position remained vacant, work was prioritized and existing staff worked more hours to fill the gap for critical projects, while some lower priority projects were deferred. However, with the growing work demands of the division (e.g. increasing number of requests for interconnection requirements studies by developers of renewable energy IPP projects), effective and timely management of the work load drove the need to again act to backfill this vacancy. Fortunately, this renewed round of recruiting resulted in identifying a qualified internal candidate for the position with significant electrical engineering experience and knowledge of HECO system particulars and its equipment and facilities. Accordingly, the internal transfer process was completed and the position was filled in November, 2006.

Q. Are there any other pending staffing changes in the Transmission Planning Division?

A. Yes. The current Director of Transmission Planning will be transferring from this role to that of Director, Strategic Initiatives, at HECO. The transfer is effective on December 25, 2006. Interviews of candidates to back-fill the Transmission Planning Director position are well underway, and we expect to fill the position in January, 2007.

Q. Please describe the Contracts Administrator position.

A. The Contracts Administrator position was transferred to the Energy Delivery Support Services Department in January, 2006, as part of a reorganization.

<u>Power Supply O&M Department (PSO&M)</u>

Q. How is the increase of 53 positions distributed within the PSO&M Department?

A. The distribution of the increase of 53 positions in the PSO&M Department is summarized below:

	2005 Recorded	2007 TY	Difference
Operations Division	144	156	12
Maintenance Division	129	161	32
Planning & Engineering Div	19	24	5
Manager and staff	7	11	4
TOTAL	299	352	53

Q. What are the general factors creating the need for the increase in staffing level of

PSO&M Department from the end of 2005 to 2007?

A. There are four general reasons why the staffing level in the PSO&M is being increased by 53 positions between the end of 2005 and 2007:

1) PSO&M Operations Division staff increased by 12 positions to operate all of HECO's generating units 24 X 7 without personnel working excessive overtime.
2) PSO&M Maintenance Division staff increased by 32 positions to perform needed preventative and corrective maintenance.
3) Planning & Engineering Division staff increased by five positions to perform requisite engineering activities in the power plants and to provide planning support for overhauls and station maintenance.
4) Department management staff increased by four positions to meet training needs and to assure environmental compliance.

The staffing requirements for each of the four groups (above) are discussed in greater detail later in my testimony.

Increased Recruitment and Hiring Efforts

Q. Has HECO experienced difficulties in recruiting new hires?

A. Yes. Over the past few years in the labor market in Hawaii it has become increasingly difficult to attract and retain qualified employees as statewide unemployment rates have decreased. The difficulties have been particularly acute in the recruitment of engineers and journey-level craftsmen (i.e., machinists, welders, instrumentation technicians, electricians, etc.).

Q. What is HECO's response to these hiring difficulties?

A. HECO has continued its professional approach to attract, qualify, hire and retain qualified employees. To address the needs of the more difficult employment market, however, HECO has expanded its efforts since 2005 in several ways to meet the need to fill the vacancies in the Power Supply Process Area, including:

1) Increased the number of dedicated Workforce Staffing and Development (WSD) consultants from one to two and a half people.
2) Increased the number of Operator Trainee (entry position) classes from 2/year to 4/year.
3) Organized and conducted the first HECO Power Supply Job Fair at the Waiau Power Plant on September 30, 2006. The job fair attracted more than 600 new applicants for positions throughout the Power Supply Process Area.
4) Increased participation with U.S. Military job fairs and placement consultants.
5) Increased job advertisements and active recruitment for mainland candidates.
6) Increased coordination with Hawaii's community colleges, including the possible development of a technical curriculum at Leeward Community College.
7) Increased the use of the internet for attracting and processing applications.
8) Reassessing the implementation of a HECO-specific apprentice program for selected trades and crafts.

Q. Can you provide an example illustrating the difficulty in filling operator positions?

A. Yes. HECO conducted a Power Supply Job Fair on September 30, 2006 to generate a larger pool of applicants for the Operator Trainee position. The Operator Trainee is the "entry" position at the bottom of the Line of Progression

(LOP) to Control Operator. Following the Job Fair, there were 395 completed applications for the Operator Trainee position. The next step was a qualification test for which 220 of the applicants appeared to take the test. Forty-three of the 220 passed the qualification test. Following this, the next step was the Assessment test, and 14 of the 43 passed this assessment. 12 of the 14 were selected for interview. One of the 12 subsequently withdrew his application as he was not able to meet the start date requirement. Ten of the initial 395 will be offered positions. This represents less than 2.5% of the applicants.

Q. Does HECO also experience difficulties hiring for positions other than "entry" level positions.

A. Yes. HECO generally experiences greater difficulties hiring for positions that require licenses (e.g., professional engineers) and certifications (e.g., trades and crafts journeymen).

<u>PSO&M Department Reorganization</u>

Q. Has the PSO&M Department been reorganized since 2005?

A. Yes. It was reorganized in June 2006.

Q. What was the purpose of the reorganization of the PSO&M Department?

A. As was described in the "HECO Splicer" announcing the reorganization (see HECO-615), the PSO&M Department was reorganized to achieve the following goals:

- Assure operation of all 14 steam-electric units 24 hours-a-day, 7 days-a-week
- Improve the technical competency of the workforce
- Produce more effective plans and prioritization of maintenance work
- Improve the execution of overhauls and major field projects

- Sustain EFOR at acceptable levels
- Sustain Heat Rates at acceptable levels

Q. How will the reorganization achieve these goals?

A. The reorganization of the PSO&M Department is intended to achieve these goals in several ways, including:

1) As shown in HECO-615, page 3, the PSO&M Organization Chart, the 3-division structure (i.e., Operations, Maintenance, and Planning & Engineering) of the department is being fortified and aligned to improve intra-department teamwork and eliminate organizational bottlenecks.

2) Critical needs are being identified and addressed, including: the need for in-field supervision of overhaul outage work; enhancing the in-house training and environmental compliance teams; and a senior analyst to focus on strategic and regulatory matters.

3) The Planning Division is being reconstituted as the Planning & Engineering Division, in part, to bring more engineering discipline to maintenance planning processes. The O&M Engineering group is being consolidated within the division, and the engineers will be deployed at the power plants. The O&M Engineers and PdM Specialists would all report to a new Sr. Supervisor for Engineering and PdM. An additional team of resource planners is being created, making three teams of two each to support overhaul planning and execution. With this organization there will be more lead time for planners to produce more effective, comprehensive overhaul plans.

4) The department-wide Operations Superintendent position is being replaced with Station Superintendents for Kahe and Waiau/Honolulu Power Plants.

The Station Superintendents will be dedicated to the safe, efficient operation of their respective generating units, and will play a major role in prioritizing and coordinating all maintenance and project work that occurs at their respective power plants.

Q. Is the reorganization consistent with the recommendations in the ESI study entitled: *"Review of HECO's Power Supply Operations, Maintenance, and Outage Management Programs* " (see HECO-607)?

A. Yes. The study commenced in March 2006 and the final report was submitted October 11, 2006. The reorganization was announced June 26, 2006. The reorganization was based, in part, on ongoing discussions with the principal investigators from ESI during the March to June 2006 time period. The observations and candidate actions presented in the final report are consistent with views represented by ESI's principal investigators during these discussions and ultimately implemented by HECO.

<u>PSO&M Operations Division</u>

Q. How many additional positions are included for the PSO&M Operations Division in the 2007 test year estimate versus the actual number in 2005.

A. There are 156 positions in the Operations Division, an increase of 12 positions from the actual staffing level of 144 at the end of 2005.

Q. When did HECO implement 24 X 7 operation of all 14 of its steam-electric generating units?

A. Waiau 3 and Waiau 4 returned to 24 X 7 operation on March 21, 2005, Honolulu 8 and Honolulu 9 returned to 24 X 7 operation on June 27, 2005.

Q. What are the general staffing requirements for operations of Kahe, Waiau, and Honolulu Power Plants on a 24 X 7 basis?

A. To operate each of the power plants on a 24 X 7 basis requires a supervisory structure that includes the Station Superintendent, Sr. Supervisor Operations, Power Plant Clerk, and Shift Supervisors. In addition, there must be a full complement of qualified operators, including: Control Operators, Jr. Control Operators, Equipment Operators; Utility Operators; and Operator Trainees.

For each of the operating positions (e.g., Kahe 1 & 2 Control Operator), filled by bargaining unit personnel, there are five employees. Each operating position must be filled all the time for 24 X 7 operation. There are three 8-hour shifts per day, which results in 21 shifts per week that must be filled. Each of the five employees that share a position is available to work five shifts per week working "regular time" (i.e., not including "overtime"). Thus, among the five employees they are available to cover 25 shifts per week, or four more than required. However, these same employees are often unavailable to work and operating shift for various reasons, including: vacation, illness, training, family leave, medical leave, attending meetings, and disciplinary suspension. If the any of the operating shifts can filled by an operator work regular time, it is filled by an operator working overtime. For an operating position that has a full complement of five qualified operators, the average amount of overtime that each operator may work in a year may range from 200 to 600 hours per year. For an operator position that does not have a full complement of five qualified operators, the average amount of overtime that each operator may work would be higher.

Q. How are the PSO&M Operations Division positions apportioned among the power plants?

A. At stated earlier in my testimony, there are 156 positions in the PSO&M

Operations Division and they are apportioned as follows:

PSO&M Operations Division – Staff Positions by Power Plant

Position	Kahe	Waiau	Honolulu	Total
Station Superintendent	1	1	--	2
Sr. Supervisor	1	1	1	3
Shift Supervisor	7	7	5	19
Control Operator	15	15	5	35
Jr. Control Operator	15	15	5	35
Utility Operator	5	10	5	20
Equipment Operator	15	15	5	35
Operator Trainee	2	2	1	5
Power Plant Clerk	1	1	--	2
Total	62	67	27	156

Kahe Power Plant. There is one Station Superintendent who has overall responsibility for Kahe Power Plant. There is one Sr. Supervisor, Operations who directly reports to the Station Superintendents, and directly supervises the Shift Supervisors. The Sr. Supervisor, Operations is primarily responsible for scheduling of operating personnel and administrative of power plant operations in accordance with HECO company policies and procedures and the Collective Bargaining Agreement with the IBEW. At any time there is at least one Shift Supervisor overseeing operations of the generating units. There are a total of seven Shift Supervisors assigned to Kahe Power Plant. If a Shift Supervisor is not overseeing operations of the generating units, he would be: overseeing maintenance activities, having a regularly scheduled time off, or on vacation, illness, training assignment, family leave, medical leave, attending meetings, or disciplinary suspension. For each pair of units there is one Control Operator, one Jr. Control Operator, and one Equipment Operator. There is also one Utility Operator for Kahe Power Plant. There is one Power Plant Clerk who performs clerical duties (e.g., time keeping, records management, mail distribution, etc.).

There are usually one or more Operator Trainees at Kahe Power Plant.

Waiau Power Plant. The personnel organization at Waiau Power Plant is very similar to that for Kahe Power Plant. The only exception is that there are two Utility Operator positions at Waiau Power Plant. Two Utility Operator positions are needed at Waiau Power Plant to support the start up and shut down of the cycling units, the local operation of Waiau 9 and Waiau 10, and because of the larger expanse of the power plant.

Honolulu Power Plant. The personnel organization at Honolulu Power Plant is similar to that of Kahe and Waiau Power Plants, but smaller because there are only two operating units. The Station Superintendent at Waiau Power Plant also has overall responsibility for Honolulu Power Plant. There are five Shift Supervisors instead of seven. The Power Plant Clerk assigned to Waiau Power Plant also performs the clerical duties for Honolulu Power Plant.

Q. Is it possible to operate all the steam-electric units on a 24 X 7 basis without having a full complements of 156 operating personnel?

A. Yes. It is possible to operate all the steam electric units on a 24 X 7 basis without having a full complement of 156 operating, however, this is only possible by existing personnel working excessive overtime, deferring training, deferring vacation, or combinations of these factors. The vacant positions can not be filled by outside contractors because of the unit-specific training and qualification that is required for operators. PSO&M averaged approximately 145 operators in 2005 and 2006. As shown on HECO-616, in 2005 and 2006, the Operations Division worked 46,920 hours and 45,954 hours of overtime, respectively. In the 2007 test year estimate, the Operations Division is expected to have 156 personnel and to work only 40,639 hours of overtime. The reduction in overtime is attributable to the increased size of the Operations Division work force. In addition, the larger work force in 2007 will enable more training of Operations Division personnel than in recent years. This is an important consideration in view of the faster rate operators are progressing through the Line of Progression and the reduced experience of operators.

Q. How does this staffing level compare to previous years?

A. HECO-617 reflects the Operations Division staffing level from 1980 to now (not including supervisory and administrative positions). Since 1980, the Operations Division staffing level has changed to reflect:

1) The commencement of commercial service of K6 in 1981 resulted in W3&4 changing from 24 X 7 to 16 X 5 operations. This resulted in a decrease in operator staffing level.
2) W3&4 returned to 24 X 7 operations in approximately 1989 when load demand increased and HECO generation margins reduced. This resulted in an increase in operator staffing level.
3) When the Independent Power Producers (AES, KPLP, and HPOWER) went into commercial operation in the early 1990's, W3&4 again changed from 24 X 7 to 16 X 5 operations in 1993. H8&9 changed from 24 X 7 to 16 X 5 operations in 1998. This resulted in a decrease in operator staffing.
4) With power demand again increasing, W3&4 returned to 24 X 7 operation beginning March 21, 2005. H8&9 returned to 24 X 7 operation beginning June 27, 2005. Staffing level was increased to support the shift staffing requirements.

In conclusion, as shown in HECO-617, whenever it has been necessary to operate all of HECO's steam electric units 24 X 7, HECO has required an operating staff of approximately 156 positions, comprised of approximately 130 operator positions and 26 supervisory and clerical positions.

PSO&M Maintenance Division

Q. How many additional positions are included for the PSO&M Maintenance Division in the 2007 test year estimate versus the actual number in 2005?

A. There are 161 positions in the Maintenance Division, an increase of 32 positions from the actual staffing level at the end of 2005.

Q. How is the PSO&M Maintenance Division organized to perform required maintenance?

A. HECO performs the bulk of required maintenance utilizing qualified trades and craft personnel, organized into Travel and Station Maintenance crews. The Travel Maintenance crews perform major overhaul work and relocate among the power plants as needed. The Station Maintenance crews are dedicated to daily preventative and corrective maintenance at each of the power plants. HECO's permanent maintenance staff is complemented by contractor personnel depending on the scope and timing of work.

Q. What is the breakdown of supervisory and trades and crafts personnel in the Maintenance Division in the 2007 Test Year estimate.

A. As shown in HECO-614, there are a total of 161 staff positions, consisting of 13 supervisory and clerical, and 148 trades and crafts positions. The trades and crafts positions are distributed among the Travel and Station Maintenance Crews.

Q. What are the 13 supervisory and clerical positions?

A. The supervisory and clerical positions in the Maintenance Division are as follows:

- (1) Maintenance Superintendent
- (1) Rotating Equipment Specialist
- (1) Maintenance Clerk
- (1) Senior Supervisor Maintenance, Overhauls
- (4) Travel Maintenance Supervisors
- (2) Kahe Station Maintenance Supervisor
- (2) Waiau Station Maintenance Supervisor
- (1) Honolulu Station Maintenance Supervisor

The Senior Supervisor Maintenance, Overhauls, is the only new supervisory position. It was added as part of the PSO&M reorganization in mid-2006 based, in part, on the candidate action identified in the ESI study (HECO-607).

Q. What is the status of night shift maintenance crew that was addressed in the 2005 test year rate case Other Production O&M testimony and discussed in the 2006 AOS?

A. Both the 2005 testimony and 2006 Adequacy of Supply filing described HECO's efforts to implement a night shift maintenance crew to allow the performance of maintenance during the off-peak periods. Since March 2006, based, in part, on the ESI study (HECO-607), HECO has concluded it can more effectively perform all the required maintenance, day and night, by bolstering its existing Station and Travel Maintenance Crews instead of creating a new night maintenance crew. Thus, the 20 maintenance positions that had been assigned to the night maintenance have been re-allocated among the existing Travel and Station Maintenance Crews. Any and all maintenance personnel will be scheduled to work night shifts as necessary to perform critical station and overhaul work.

As stated in the 2006 AOS, "Planned outages and maintenance outages also reduce generating unit availabilities." Bolstering the existing Travel and Station Maintenance Crews will also enable consideration of working more hours per day (i.e., multiple crews) on critical path activities during overhauls. Accordingly, durations of planned and maintenance outages are expected to be shorter in the future with a full complement of maintenance personnel.

Q. What is the basis for HECO's maintenance work force in the 2007 test year estimate?

A. Based on the maintenance work load over the past few years, the long-term planned maintenance schedules, experience using contractors, the backlog of maintenance work orders, and the anticipated work for future years, HECO has affirmed that the Maintenance Division staffing level proposed for 2005 test year (160 positions) is valid for 2007 test year (161 positions). As will be described in more detail below, the 2007 test year total includes the additional position of Sr. Supervisor, Overhauls. Also as will be described later in testimony, HECO was unable to fill all of the 2005 positions as planned and consequently relied on contracted services and additional overtime to perform the required maintenance work.

Q. Please explain the need for Maintenance Division staffing level increases between actual 2005 and budget 2007.

A. In the 2005 test year Production O&M Expense Direct Testimony, a Maintenance Division staff level of 160 was proposed, including 20 positions for a night maintenance crew. Today, the maintenance needs are similar and the Maintenance Division staff level that is required to perform the work in 2007 is 161, or one more than that envisioned in 2005. As discussed previously in my testimony, the needs are similar today, however, the approach being implemented to perform the necessary maintenance has changed from that envisioned in 2005 (i.e., night crew positions be assigned to Travel and Station Maintenance Crews).

Q. What was the actual Maintenance Division staff level at the end of 2005?

A. The Maintenance Division staff level at the end of 2005 was 129, or 31 less than that budgeted. This shortage was primarily due to difficulties in hiring qualified trades and crafts personnel to fill vacant positions.

Q. What have been the consequences of a Maintenance Division with 31 vacancies?

A. As a result of having approximately 31 vacancies (some months more and some months less during the period from 2005 to 2006) in the Maintenance Division since 2005, HECO has experienced the following consequences:

1) The utilization of contractors to perform maintenance work that would otherwise be performed by its staff was increased,
2) the level of overtime worked by its staff was increased, and
3) the backlog of lower priority work has grown.

Q. Can you illustrate higher outside services expenses to perform maintenance during this period?

A. As shown in HECO-618 (HECO-626 for the 2005 test year), the 2005 test year estimate for Other Production Maintenance Non-Labor Expense, the Outside Services expense was proposed to be $10,365,000. As shown in HECO-619, of this total, $8,980,000 was for Outside Services in support of the Travel and Station Maintenance Crews. Also shown in HECO-619, in 2005 the actual outside services expense for maintenance was $13,795,000 or $4,815,000 higher than that budgeted. Similarly, as shown in HECO-619, the 2006 budget included $9,283,000 for Outside Services in support of the Travel and Station Maintenance Crews. Also shown in HECO-619, in 2006 the actual outside services expense for maintenance was $12,772,000, or $3,489,000 higher than that budgeted.

Q. Does the 2007 test year estimate include 161 maintenance personnel from January 1, 2007?

A. Yes.

Q. How does the 2007 estimate for Other Production Maintenance Non-Labor Expense, Outside Services in support of the Travel and Station Maintenance Crews compare to actual expenses in 2005 and 2006?

A. The 2007 estimate for Other Production Maintenance Non-Labor Expense, Outside Services in support of the Travel and Station Maintenance is $12,313,000, or $1,482,000 and $459,000 less than the amounts expended in 2005 and 2006, respectively. However, the 2005 and 2006 expenses are net values after reimbursement by insurance of $2,155,000 and $400,000, respectively. Moreover, the 2007 test year expense includes $1,909,000 for other program costs to be performed in 2007, such as Smart Signal ($299,000 after normalization), Kahe fuel tank clean inspection ($450,000), and Kahe sludge pond cleaning ($1,160,000).

Q. What are the comparable levels of overtime for the Maintenance Division in 2005, 2006, and 2007?

A. As shown on HECO-620, in 2005 and 2006, the Maintenance Division worked 60,699 hours and 66,976 hours of overtime, respectively. In the 2007 estimate, the Maintenance Division is expected to have 161 personnel and to work 62,975 hours of overtime. The reduction in overtime is attributable to the increased size of the Maintenance Division work force.

Q. Can you provide examples of lower priority work that was not performed?

A. Yes. Although they were included in the PS O&M budgets, in 2005 and 2006 the following projects were not performed, in part, because of the vacancies that existed in the Maintenance Division:

Location	Description	2005	2006
Honolulu	Cathodic Protection	$150,000	--
Honolulu	Building Repairs	--	$100,000
Kahe	Basin Intake Dredging	--	$150,000
Kahe	Cathodic Protection	$150,000	$150,000
Waiau	Travel Screens Overhaul	$150,000	--
Waiau	Cathodic Protection	$150,000	$150,000
Waiau	Circ Water Spalling Repairs	--	$100,000
	Total	$600,000	$650,000

In addition, the backlog of maintenance work orders has grown to more than 2,000 items as of November 30, 2006.

Q. Please describe the backlog of maintenance work.

A. As of April 2006, there were more than 4,000 work orders in the backlog of maintenance work orders. The first step was to purge the backlog of work orders for which the work had been completed, but for which the records had not been updated. By May 2006, this exercise had been completed and the total number of work orders in the back log had been reduced by approximately 25% to approximately 3,000. Of this total, approximately 1,700 are for Waiau Power Plant, 1,000 are for Kahe Power Plant, and 300 are for Honolulu Power Plant.

Each week about 100 new work orders are added and about the same amount are cleared because the required maintenance was performed. During overhauls the work orders that apply to the generating unit being overhauled are typically cleared. In 2007, the expectation is that the backlog will be reduced significantly when the Maintenance Division work force is at its full complement.

Q. How does Maintenance Division trades and crafts staffing level compare to previous years?

A. HECO-617 shows the Maintenance Division trades and crafts staffing level from 1980. Today's staffing requirement for maintenance trades and crafts personnel is the same as that experienced throughout the 1980s when the generating system was operated with similar duty and similar reserve margins. The 2007 test year estimate of 148 maintenance trades and crafts personnel is equivalent to that during the 1980s.

<u>PSO&M Planning & Engineering Division</u>

Q. How many additional positions are included for the PSO&M Planning and Engineering Division in the 2007 test year estimate versus the actual number in 2005?

A. There are 24 positions in the Planning and Engineering Division, an increase of five positions from the actual staffing level at the end of 2005.

Q. What positions are included in the Planning and Engineering Division?

A. The Planning & Engineering Division is comprised of the following positions:

- P&E Superintendent 1
- Power Plant Clerk 1
- Work Management Specialist 1

• Planning Sr. Supervisor	1
• Resource Planners	10
• Engineering Sr. Supervisor	1
• O&M Engineers	6
• PdM Specialists	3
TOTAL	24

Q. How is the Planning and Engineering Division organized?

A. In mid-2006, the Planning Division of the PSO&M Department was the renamed the Planning & Engineering Division, and the dispersed engineering functions within the department were consolidated into this division. The division is subdivided into two groups: (1) Planning, and (2) Engineering and PdM (Predictive Maintenance). The Planning group is comprised of the Planning Sr. Supervisor and ten Resource Planners; six of the Resource Planners are dedicated to planning and implementing overhauls and major project work, and the remaining four Resource Planners are dedicated to planning station maintenance work. Increased emphasis is being placed on the planning activities in support of overhauls, maintenance outages, and engineering projects being implemented within the scope of overhauls. All of the Resource Planners report to the Senior Supervisor, Planning.

The Engineering and PdM group is further divided into two sub-groups. One sub-group includes six O&M Engineers that are stationed in the power plants. The six O&M Engineers perform diversified technical assignments in support of daily engineering needs in the power plants, including troubleshooting, performance testing, project coordination, and engineering analysis. The other subgroup includes the three PdM Specialists that perform

PdM testing and analysis at all of HECO's power plants. The PdM ("predictive maintenance") work will continue to be performed utilizing the same number of staff personnel in 2007 that existed in 2005. The Engineering Sr. Supervisor oversees the Engineering and PdM sub-groups.

Other PSO&M Staff Additions

Q. What other additional staff positions resulted from the reorganization of the PSO&M Department in mid-2006?

A. The following four positions are additions:

- Sr. Supervisor, Training
- Sr. Trainer
- Sr. Technical Analyst
- Environmental Compliance Specialist

Q. Can you expand on the need for increased training?

A. HECO's PSO&M workforce is young and training requirements are increasing. There are more employees to be trained and more training required to develop and maintain skill levels. HECO recognized the need for more formalized training across the PSO&M Department. Accordingly, it is expanding its dedicated training staff to three positions in the 2007 test year estimate, an increase of two versus the actual level in 2005. One of the two positions was filled in 2006.

Q. Please describe HECO's increased commitment to training?

A. HECO has committed to increasing the level of training for operators and maintenance personnel. The following steps have been taken to move forward with this commitment.

1) A new Training Division was created in June 2006.

2) A Senior Supervisor has been assigned to lead the new Training Division in developing new training programs and to expand existing programs.

3) During portions of the year, the full complement of 156 operator positions will allow operators not required to be on shift to attend training without being on overtime. Also, on occasion fully qualified operators will be utilized to conduct training sessions.

Q. How is this commitment to training reflected?

A. Expenditures for training have increased since 2003, and will increase further in 2007. HECO-621 provides a graphical plot of this increase in training expense. Since 2003, total training expenses have increased from $1,493,000 in 2003 to $3,175,000 in 2005, and are expected to increase to $3,456,000 in 2007.

Q. What is the Sr. Technical Analyst position?

A. The Sr. Technical Analyst is needed to support the diversified strategic activities in the Power Supply Process Area, including: strategic planning, engineering analyses, regulatory filings; budgeting, and emergency contingency planning. This new staff position reports directly to the PSO&M Manager.

Q. Why is a second Environmental Compliance Specialist being added to the staff?

A. The need for two Environmental Compliance Specialists in the PSO&M Department was recognized in the 2005 test year rate case testimony, but the second position was not filled. As a consequence, the existing Environmental Compliance Specialist had to work overtime to perform the required work. With the increase in regulatory compliance work envisioned for 2007, both positions need to be filled to perform required work.

OTHER PRODUCTION O&M EXPENSE

Q. What is included in Other Production O&M Expense?

A. Other Production O&M Expense includes expenses incurred to ensure reliable, efficient, safe and compliant operation and maintenance of HECO's 14 steam, two combustion turbine, and 18 Distributed Generator units at three power plants and associated facilities.

Q. What HECO departments contribute to Other Production O&M Expense?

A. The majority of Other Production O&M Expense is incurred in the Power Supply Operations and Maintenance (PSO&M) Department, the Technical Services Division of the Power Supply Engineering Department, and the Administrative staff in the Power Supply Services Department. Portions of the Environmental Department, System Operation Department, Purchasing and Materials Management Department, Transportation & Facilities Maintenance Department, Engineering Department, Information Technology Services Department, Generation Planning Department, Energy Services Department and other HECO departments also contribute to Other Production O&M Expense.

Q. How was Other Production O&M Expense developed for HECO's 2007 test year?

A. The test year estimate is based on HECO's 2007 operating budget, with three adjustments and three normalizations. The test year estimate is the sum of our estimates for Other Production Operations Expense - Labor and Non-labor accounts as shown in HECO-622, and for Other Production Maintenance Expense - Labor and Non-labor accounts, as shown in HECO-623. A more detailed discussion of how Other Production O&M Expenses were developed follows. The three adjustments are shown in HECO-624 and the three normalizations are shown in HECO-625.

Q. What was the first adjustment made to the 2007 operating budget to develop the 2007 test year estimate of Other Production O&M Expense?

A. The first adjustment is a decrease of $155,000 in Other Production Operations Non-labor due to overstatement of Distributed Generator (DG) unit rental expense. Total DG O&M expenses are reduced from $3,620,000 to $3,465,000.

Q. What was the second adjustment made to the 2007 operating budget to develop the 2007 test year estimate of Other Production O&M Expense?

A. The second adjustment was an increase of $42,000 for Abandoned Projects. Please refer to Ms. Patsy Nanbu's testimony, HECO T-10, for additional discussion related to this adjustment.

Q. What was the third adjustment made to the 2007 operating budget to develop the 2007 test year estimate of Other Production O&M Expense?

A. The third adjustment was to remove $279,000 of performance incentive compensation expenses. Please refer to Ms. Patsy Nanbu's testimony, HECO T-10, for additional discussion related to this adjustment.

Q. What was the effect of the three adjustments on Other Production expenses for HECO's 2007 test year?

A. The combined effect of the three adjustments was to decrease the 2007 operating budget amount for Other Production Operations – Non-labor by $392,000 as shown in HECO-624.

Q. What was the first normalization made to the 2007 operating budget to arrive at the 2007 test year estimate of the Other Production O&M Expense?

A. HECO proposes a normalization of ten thirteenths ($10/13^{th}$) for Emissions Fees, based on HECO's payment of emission fees in 10 of the past 13 years. HECO maintains that the administration of the fee by the Department of Health is not predictable, however, for 2007 test year HECO is utilizing the 10/13th's methodology to determine the Emissions Fee adjustment. Thus, for ratemaking purpose, the normalized fee was based on 10/13th of the 2007 forecast amount of $1,090,000, or $838,000, to derive the 2007 test year normalization adjustment of $252,000.

Q. What is the second normalization made to the 2007 operating budget to arrive at the 2007 test year estimate of the Other Production O&M Expense?

A. HECO proposes to amortize the $897,000 expense for Smart Signal software over three years. Thus, for ratemaking purpose, the normalized amount is 1/3 of the 2007 forecast amount of $897,000, or $299,000, to derive the 2007 test year normalization adjustment of $598,000.

Q. What is the third normalization made to the 2007 operating budget to arrive at the 2007 test year estimate of the Other Production O&M Expense?

A. The third normalization adjustment is an increase of $31,000 for Integrated Resource Planning. Please refer to Mr. Alan Hee's testimony, HECO T-9, for more detailed discussion of this normalization adjustment.

Q. What is the effect of the three normalizations on Other Production expenses for HECO's 2007 test year?

A. The effect of the three normalizations is to decrease the operating budget amount for Other Production Operations & Maintenance – Non-labor by $819,000 as shown in HECO-625.

Q. What was the net effect of the adjustments and normalizations on Other Production O&M Expense for HECO's 2007 test year?

A. The net effect of the adjustments and normalizations is to decrease the total of Other Production O&M Expense by $1,211,000 to the 2007 test year amount of

$68,222,000 as shown in HECO-602.

Other Production Operation Expense

Q. What is the 2007 test year estimate for Other Production Operations Expense?

A. The 2007 test year estimate for Other Production Operations Expense is $29,112,000. Of this total, $14,242,000 is for Labor expense and $14,870,000 is for Non-labor Expense as shown in HECO-602.

Q. What was the basis for the 2007 test year estimate for Other Production Operations Expense?

A. The 2007 test year estimate is based on the operating budget for 2007, with the adjustments and normalizations mentioned above.

Q. How was the 2007 Other Production Operations Expense determined?

A. The Other Production Operations Expense was determined by forecasting the labor and non-labor requirements necessary to provide reliable, safe, efficient, and compliant electric power for distribution.

Other Production Operations – Labor Expense

Q. What was included in the Other Production Operations - Labor Expense?

A. The Other Production Operations - Labor Expense includes salaries and wages for operator and non-operator costs.

Q. What operator costs are included in the Other Production Operations - Labor Expense?

A. Operator wages make up the majority of the operator costs in the Other Production Operations - Labor forecast. The forecast also includes the expense for supervision, plant operation, administration, chemists, environmental specialists, and training.

Q. What non-operator costs are included in the Production Operations - Labor forecast?

A. Non-operator costs in the Other Production Operations Labor forecast include wages and salaries for labor required to keep the plant and associated facilities operating safely, compliantly, efficiently and reliably on a day-to-day basis; environmental services to meet regulatory requirements; and power purchase contract management.

Q. How was the labor expense for operator costs forecasted?

A. The operator cost was developed by identifying manpower and supervision requirements to support 24 X 7 operations at the Kahe, Waiau and Honolulu Power Plants and associated facilities. The labor forecast derivation also includes estimates of overtime costs and non-productive wages to account for vacation, holidays, sick leave, family leave, attending company meetings, and training. The labor forecast derivation assumes that all of the 156 Operations Division positions are filled for the whole year.

Q. How was the labor expense for non-operator costs forecasted?

A. Labor expense for non-operator costs is forecasted by the respective HECO departments based on the support required. For example, the relay section of the System Operation Department normally tests and maintains protective relays in the generating plants. The labor cost to provide this service falls under the non-operator costs in the Other Production Operations - Labor Expense.

Q. How does the 2007 test year Other Production Operations - Labor Expense of $14,242,000 compare with 2005 recorded?

A. The 2007 Other Production Operations - Labor Expense is $1,938,000 or 16% higher than the recorded 2005 amount as shown on HECO-622.

Q. What makes up the increase of $1,938,000?

A. HECO-WP-601 reflects five different NARUC accounts reflecting increases greater than $200,000 and 10%. The total of these five accounts is $1,690,510 or 87% of the increase. The first three increases are $479,603 (in NARUC account 502020 at Waiau), $278,308 (in NARUC account 502030 at Kahe), and $466,456 (in NARUC account 505020 at Waiau). These increases are the result of wage and salary increases plus the increase in staffing in the Operations Division by 12 positions for the full year that was discussed earlier in my testimony. The fourth increase is $234,219 (in NARUC account 503020). This increase is the result of a change in allocation of software maintenance and purchase expense. Please refer to the testimony of Ms. Patsy Nanbu, HECO T-10, for additional explanation. The fifth increase is $231,924 (in NARUC account 506020). For budgeting purposes, Environmental Department budgets labor for wastewater support to Waiau Station only. Actual costs are recorded to individual accounts for Kahe, Waiau, and Honolulu power plants. This code block cost is not comparable from 2005 to 2007 test year.

Q. What factor contributes to the above increases between 2005 recorded and 2007 test year Other Production Operations – Labor Expense?

A. Wage increases for bargaining unit employees are in accordance with the Company's negotiated labor agreement with the International Brotherhood of Electrical Workers, Local 1260. Wage increases for merit personnel occur annually in May with some wage adjustments occurring in September. As a result of the projected wage increases, on an annual basis, general wage rates for Test Year 2007 are expected to be 6.53% (for bargaining unit employees) and 7.64% (for merit employees) higher than the respective 2005 wage rates. Ms.

Nanbu in HECO T-10 discusses the relative wage rates between 2005 and 2007 based on the wage increase assumptions for bargaining unit and merit employees discussed by Ms. Price in HECO T-12.

Q. Please summarize the $1,938,000 or 16% increase in Other Production Operations labor from 2005 actual to test year 2007 forecast.

A. The increase in Other Production Operations Labor between 2005 Actual and 2007 test year has been previously discussed and is primarily due to the incremental costs for wage and salary increases plus additional staffing to support 24 X 7 operation of the 14 steam generating units at a reasonable level of overtime.

<u>Other Production Operations – Non-labor Expense</u>

Q. What was included in Other Production Operations - Non-labor Expense?

A. This cost category includes the outside services for operation and maintenance of Distributed Generators (DG) at HECO's substations. It also includes consumable items such as chemicals (used for boiler, waste and circulating water treatment), lubricants, gases, instrument chart paper, city water and sewer charges, and office supplies. Expenses for technical training, transportation, waste removal, janitorial services, and weed control services are also included.

Q. Are non-operator non-labor costs forecasted in Other Production Operations - Non-labor Expense?

A. Yes. Other Production Operations – Non-labor Expense includes forecasts of non-operator non-labor costs such as: items for operational maintenance, technical training, environmental services and fees, purchase power contract management, and outside services.

Q. How was Other Production Operations - Non-labor Expense forecast?

A. Other Production Operations - Non-labor Expense is forecast for Kahe, Waiau, and Honolulu Power Plants and the DG facilities on the basis of projecting known recurring costs. Non-operator non-labor expenses required to keep the plant operating efficiently and reliably and in compliance with all applicable environmental and other government regulations on a day-to-day basis is forecasted by the respective HECO departments and divisions directly involved with the work.

Q. How does the 2007 test year Other Production Operations - Non-labor Expense compare with 2005 recorded expenditure?

A. As shown in HECO-622, the 2007 test year Other Production Operations - Non-labor Expense of $14,870,000, after adjustments and normalizations, is $4,716,000 or 46% higher than the 2005 recorded amount of $10,154,000.

Q. What was the increase attributed to?

A. HECO-626 shows the breakdown of the 2005 Actual versus 2007 test year variance of $4,716,000. The increase is attributed to the net impact of variances in the expense categories consisting of material, outside services, transportation, labor on-cost, and the budget and normalization adjustments.

Q. Referring to HECO-626, please provide an explanation for the Other Production Operation – Non-labor variances by expense category.

A. Other Production Operation – Non-labor differences between 2005 Actual and 2007 TY are provided below:

- Material – Changes in 2007 test year estimate result in a net decrease of $101,000 for non-labor materials expenditures.
- Transportation – The $34,000 increase in non-labor transportation expenses is due to increased vehicle and transportation charges.

- On-Cost – Labor related on-cost is captured as a Non-labor expense and is comprised of Energy Delivery on-cost and Power Supply on-cost and results in a $169,000 decrease.
- Outside Services - The $5,565,000 increase in non-labor outside services expenditure, after applying the adjustments and normalizations in HECO-624 and HECO-625, is reduced to $4,952,000. The increase in the cost for outside services between 2005 recorded and the 2007 test year estimate of $4,952,000 (after adjustments and normalizations) makes up most of the increase in Other Production Operations – Non-labor Expense. As discussed in detail below, approximately 67% of this increase is attributable to DG.

  HECO-WP-601 lists the expense items with variances of greater than $200,000 and 10% when comparing 2005 actual to 2007 test year. HECO-WP-601 reflects six different NARUC accounts reflecting increases greater than $200,000, that total $4,676,000 or 94% of the increase. The expenses identified in HECO-WP-601 in Production Operation Non-labor Outside Services with a variance greater than $200,000 are:

  - $406,000 (in NARUC account 548, expense element 501) and $2,916,000 (in NARUC account 548, expense element 570) for a total of $3,322,000 for Distributed Generator (DG) and Dispatchable Standby Generator (DSG) expense. These expenses will be discussed in greater detail below.
  - $321,000 (in NARUC account 500020) for Kahe Unit 7 amortization.

- $279,000 (in NARUC account 506030) for performance incentive compensation expense. As previously discussed in this testimony, this expense has been removed.
- And $249,000 (in NARUC account 549, expense element 501, account number 730) and $505,000 (in NARUC account 549, expense element 501, account number 731) for a total of $754,000 in New Technology expense.

Each of these expenses are discussed in greater detail below.

Distributed Generator (DG) Expenses

Q. What expense for DG did HECO experience in 2005?

A. The total expense for DG in 2005 was $341,000, primarily for the lease of DG units during the month of December.

Q. How has HECO's expense for DG increased since 2005?

A. As shown in HECO-627, the 2007 estimate for total DG O&M expenses is $3,465,000, which is $3,124,000 greater than that in 2005. Two variance line items of $406,000 for outside services and $2,916,000 for rental expense, a total of $3,322,000, were identified in HECO-WP-601 for DG expense. As defined above as "the first adjustment made to the 2007 operating forecast to develop the 2007 test year estimate of Other Production O&M Expense," the DG rental expense in the budget assumed that all nine new DG units would be up and running for all of 2007. Three of the units are now slated for March 2007. Rental expense was adjusted to reflect, removing 2 months of rental expense for that site. That adjustment, and a revision to the monthly rental rate, resulted in a downward adjustment of $155,000. The variance for DG rental expense is then reduced from $2,916,000 to $2,761,000.

Q. Why has HECO's expense for DG increased significantly since 2005?

A. HECO has made a significant commitment to Substation DG since 2005, in part, to stem the consequences of a shrinking reserve capacity margin until additional generating capacity can be brought on to the system.

Q. Please describe HECO's DG resources and when they were or will be commissioned to service.

A. HECO's DG installations are comprised of the following:

1) Nine leased 1.64 MW diesel generating units totaling 14.76 MW installed at HECO's Ewa Nui Substation, Helemano Substation, and Iwilei Tank Farm and placed in service in 2005;
2) Three leased 1.64 MW diesel generating units totaling 4.92 MW installed at HECO's Campbell Estates Industrial Park ("CEIP") Substation and placed in service in November 2006;
3) Three leased 1.64 MW diesel generating units being installed at HECO's Kalaeloa Poleyard that are projected to be in service in December 2006;
4) Three leased 1.64 MW diesel generating units totaling 4.92 MW to be installed at HECO's Ewa Nui Substation in the first quarter of 2007; and
5) One 1.64 MW utility-dispatchable, customer-owned standby generator unit to be installed at Kaiser Foundation Hospital Moanalua Medical Center ("Kaiser Hospital") in the third quarter of 2007.

Q. What is the purpose of these DG resources?

A. The primary purpose of these DG units is to provide HECO with dispatchable, firm generating capacity for peaking purposes. As described in the 2006 AOS, HECO is employing DG resources to mitigate the reserve capacity shortfalls anticipated over the next several years.

Q. What is the current status of the HECO-sited DG units?

A. As described above, twelve DG units are currently in service, at HECO's Ewa Nui, Helemano, and CEIP substations and Iwilei Tank Farm. Construction work is currently in progress at both Kalaeloa Poleyard and Ewa Nui Substation. All necessary permits have been received including noncovered source air permits. All major equipment items including the DG units, transformers, fuel tanks, and switchgear have been ordered or already received. Startup testing began the week of December 18, 2006 at the Kalaeloa Poleyard and the three units at that site will be available for service shortly thereafter this month. Startup testing of the three DG units being added at Ewa Nui Substation will begin in February, 2007, leading to a projected in service date of March 1, 2007.

Q. Please describe the nature of the Kaiser Hospital DSG project.

A. The Kaiser Hospital project will be HECO's first implementation of dispatchable standby generator ("DSG"). DSG refers to the active operation of customer-owned standby generators by the electric utility to meet utility system needs. As such, the generating units serve dual purposes as emergency generators for a customer facility and as limited duty distributed generating units for the utility. The DSG concept that HECO is pursuing at Kaiser Hospital is based on the DSG tariff used by Portland General Electric ("PGE") and approved by the Oregon Public Utilities Commission.

The 1.64 MW emergency power facility will primarily be funded and owned by Kaiser Hospital. Under HECO's DSG proposal, HECO would contribute some upfront funding to Kaiser Hospital to pay for equipment that would allow HECO to remotely start and stop the Kaiser standby generator to supplement HECO's grid capacity as needed for up to 1,500 run hours per year.

Regardless of whether HECO is dispatching the generator or not, the facility would serve Kaiser Hospital with emergency power if grid power were lost. HECO would reimburse Kaiser Hospital for fuel costs, pay for routine maintenance and permitting, and provide a monthly incentive payment. The electricity generated by the DSG facility would be considered as utility power since HECO is providing the fuel and maintenance of the unit.

Q. What are the benefits of a DSG arrangement between HECO and Kaiser Hospital?

A. The potential benefits of this DSG arrangement to Kaiser Hospital include (1) reduced or avoided capital, operations, and maintenance costs, (2) improved generating unit reliability due to regular startups and testing under load, and (3) utility consulting and collaboration. The primary benefits to HECO of such an arrangement are the provision of cost-effective utility system reserve capacity and the ability to support the operation of a critical customer.

Q. What is the current status and projected timeframe for the Kaiser DSG project?

A. The rights and obligations of Kaiser Hospital and HECO are being documented and defined in a DSG agreement currently under negotiation. HECO anticipates execution of the Kaiser Hospital DSG agreement in January, 2007. The DSG agreement would be submitted to the PUC approximately one month later in February, 2007 for review and approval. Operation of the DSG unit at Kaiser Hospital is anticipated to begin in August, 2007.

Q. What kind of equipment is HECO making a contribution towards?

A. HECO would be paying Kaiser primarily for the incremental costs associated with the installation of paralleling switchgear, as opposed to non-paralleling switchgear that Kaiser would have otherwise installed were it not for the DSG arrangement. The paralleling switchgear allows the generating unit to be operated in synchronization with the utility electric system. Put another way, with parallel operation, the facility can be served simultaneously by utility power and by generator power. Under the DSG concept, this means that when the utility dispatches the customer generating unit, the facility is also being served at the same time by normal grid power. Not only does this maintain reliability, since the customer is not forced to rely solely on generator power, but the customer facility also sees no interruptions of service when the generator is turned on or off. PGE determined that this is a key operational component to allow the acceptability of utility dispatch of customer emergency generators.

Q. What is the estimated contribution and how will it be accounted for?

A. The contribution is estimated to be $675,000. In its application seeking approval of the agreement, HECO will also seek Commission approval to record the contribution to a miscellaneous deferred debit account (a regulatory asset) upon payment. HECO will propose to amortize this regulatory asset over the service period of the DSG unit within the term of the DSG contract. Since the proposed ten year contract will begin six months prior to the anticipated date of service on August 2007, the regulatory asset will thus be amortized over nine and a half years.

Q. Why does HECO propose to record the contribution paid to Kaiser as a regulatory asset?

A. The equipment will be owned by Kaiser and not HECO, therefore, this equipment will not be included in plant-in-service. Ratepayers will benefit from the operation of this equipment. Therefore, HECO proposes to record the contribution to a deferred debit account (a regulatory asset) and proposes that it be recovered from ratepayers over the period that ratepayers will benefit from the contribution. The rate impact is essentially the same as if the equipment was recorded as plant in service. Including the amortization expense in revenue requirements would be similar to including depreciation expense in determining revenue requirements. Likewise, including the unamortized balance in rate base, would be similar to including the undepreciated plant-in-service balance in rate base.

Q. How is the contribution reflected in this application?

A. This application reflects the proposed regulatory asset treatment of the contribution. The amortization in the test year is $30,000, which represents five month's amortization, as illustrated in HECO-628. This expense is included in other production operation and maintenance. The unamortized regulatory asset balance is included in rate base and is further discussed by Ms. Gayle Ohashi in HECO T-17.

<u>K7 Amortization</u>

Q. What is the amount of the Kahe Unit 7 amortization expense in the 2007 test year estimate?

A. The Kahe Unit 7 amortization expense in 2007 test year estimate is $321,000 based on the HECO 2005 Test Year Rate Case – Stipulated Settlement Letter, dated September 16, 2005.

<u>New Technologies</u>

Q. What is the amount of New Technology expense in the 2007 test year estimate?

A. The 2007 estimate for research and development expense is $1,181,000 as shown in HECO-629.

Q. Please provide a breakdown of the major R&D activities on which these funds will be expended.

A. The major R&D activities include:

1) local EPRI matching funds ($249,000),
2) recurring renewable energy funds ($65,000),
3) renewable energy initiative ($300,000),
4) biofuels initiatives ($100,000),
5) electronic shock absorber ($221,000),
6) Sun Power for Schools ($40,000),
7) labor ($104,000),
8) overheads ($76,000), and
9) other activities ($25,000).

Q. In general terms, how are HECO's local research and development costs budgeted?

A. In general, the estimate includes expenses associated with near-term locally-based research and development activities to further HECO's evaluation and implementation of new technologies related to electric utility operations, renewable energy, alternate energy, and emerging technologies and labor related to Technology Division, Senior Vice President Energy Solutions, and Integrated Resource Planning Division. HECO's local research and development costs are budgeted to further HECO's near-term research and development, studies, evaluation and implementation of renewable energy, alternate energy, and emerging technologies. The intent of the local research and development funding is to fund projects and studies that are directly related to HECO issues that may not be addressed under the general EPRI membership research package. The research activities will concentrate on areas where the project results will have impact and bearing on the technology or project that could be implemented by HECO in the near-term. These activities would include, but are not limited to, technology research, development and demonstration, feasibilities studies, resource data collection, land availability studies, collecting information on technology performance, cost, emission, etc. and other activities. A detailed discussion of R&D activities is set forth in HECO-629.

Q. Does the 2007 test year estimate include R&D expenses for renewable energy?

A. Yes. The budgeted amount reflects increased activities in the renewable energy and alternate energy areas. The new initiatives are related to wind, biofuels and other renewable energy, alternate energy and emerging technologies (such as hydrogen and fuel cells). The increased activities are a direct reflection of HECO's strong commitment to increase its operational efficiency, offer new energy solutions, and increase its renewable energy portfolio.

Q. Please provide an example of a renewable energy initiative using wind.

A. A portion of the 2007 funds are expected to be used for the assessment and evaluation of a wind farm development at a Kahuku military site. HECO has been in communications with the Army to develop a wind farm in the Kahuku training area. Based on ongoing discussions with the Army, the site may be leased by HECO and HECO would then competitively bid for a wind project developer. HECO has submitted to the Army a proposed wind monitoring program to allow HECO subcontractors to install, monitor, and evaluate the wind speed and direction at multiple sites for a minimum one-year period. HECO is awaiting Army Corps and Department of Fish & Wildlife review and approval of this program. HECO is also awaiting approval of a Conservation District Use Permit by the State of Hawaii Department of Land and Natural

Resources. The 2007 funds will be used to fund the stationary meteorological tower and sensors and mobile acoustical trailer and installation, monitoring, evaluation and reporting of this effort.

Q. Please provide an example of a renewable energy initiative using biomass or biofuels.

A. HECO has an active multi-year, multi-phase research and development program to examine biofuels for stationary power generation consisting of the following: Phase 1 – Biofuels resource assessment; Phase 2 – Combustion testing; Phase 3 – Generating unit assessment and infrastructure and operational assessment; and, Phase 4 – Utility-scale demonstration. Phase 1 and Phase 2 have been completed. For a more detailed discussion of the results of Phase 1 and Phase 2 and activities planned for Phase 3, please refer to HECO-629.

<u>Summary of Other Production Operations Expense</u>

Q. Is HECO's estimate of the test year 2005 Other Production Operations Expense reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the resources required to operate HECO's generating units 24 X 7 while maintaining compliance with all environmental and other regulations and permit requirements.

<u>Other Production Maintenance Expense</u>

Q. What is the test year 2007 estimate for Other Production Maintenance Expense?

A. As shown on HECO-602, the test year 2007 estimate for Other Production Maintenance Expense is $39,110,000. Of this total, $15,219,000 is for labor expenses while $23,891,000 is for non-labor expenses.

Q. What was the basis for the 2007 test year estimate for Other Production Maintenance Expense?

A. The 2007 test year estimate is based on the operating budget for 2007 with the normalization mentioned above.

Q. How was the 2007 Other Production Maintenance Expense determined?

A. The Other Production Maintenance Expense was determined by forecasting the labor and non-labor requirements necessary to provide reliable, safe, efficient, and compliant electric power for distribution.

<u>Other Production Maintenance – Labor Expense</u>

Q. How does HECO forecast the labor portion of the Other Production Maintenance Expense?

A. Labor expenses for Other Production Maintenance is the summation of labor forecasts for work to be performed by maintenance personnel in the three Station Maintenance groups, the Travel Maintenance group, and other non-maintenance personnel who support maintenance of the generating units and their associated facilities. Labor forecasts are based on staffing level using standard labor rates, less estimated labor for capital projects, and an estimated amount of overtime.

Q. How does the 2007 test year estimate of Other Production Maintenance - Labor Expense of $15,219,000 compare with the 2005 recorded expense?

A. The test year 2007 Other Production Maintenance - Labor Expense is higher than the 2005 recorded by $4,700,000, or 45%, as shown on HECO-623.

Q. What are the increases attributable to?

A. The difference is primarily attributable to additional maintenance personnel, approximately 32 positions, whose labor costs are included in the 2007 Other

Production – Labor Expense for the entire year. In 2005, the actual labor costs were substantially lower. As discussed in detail earlier in my testimony, the consequences of the smaller maintenance staff in 2005 (and also in 2006) were: (1) HECO utilized contractors to perform maintenance work that would otherwise be performed by its staff; (2) HECO maintenance personnel worked additional overtime; and (3) the backlog of lower priority work has grown.

Q. What other factor contributes to the above increase of $4,700,000 shown in HECO-623 between 2005 recorded and 2007 test year Other Production Maintenance – Labor Expense?

A. Wage increases for bargaining unit employees are in accordance with the Company's negotiated labor agreement with the International Brotherhood of Electrical Workers, Local 1260. Wage increases for merit personnel occur annually in May with some wage adjustments occurring in September. As a result of the projected wage increases, on an annual basis, general wage rates for Test Year 2007 are expected to be 6.53% (for bargaining unit employees) and 7.64% (for merit employees) higher than the respective 2005 wage rates. Ms. Nanbu in HECO T-10 discusses the relative wage rates between 2005 and 2007 based on the wage increase assumptions for bargaining unit and merit employees discussed by Ms. Price in HECO T-12.

Q. Did you compile a listing of variances greater than $200,000 and 10% between 2005 recorded costs and the 2007 test year estimate?

A. Yes. HECO-WP-601 summarizes the variances greater than $200,000 and 10% between 2005 recorded costs and the 2007 test year estimate. However, my testimony does not address each of the individual variances identified in this work paper. The primary reason is that Other Production O&M Maintenance –

Labor expenses typically are allocated to different activities and RAs depending upon the specific generating units being worked upon which vary from year to year. In addition, my testimony is addressing the differences in the Other Production O&M Maintenance – Labor expense by explaining how the required maintenance was performed in 2005 and will be performed in 2007 utilizing HECO's maintenance personnel.

<u>Other Production Maintenance – Non-labor Expense</u>

Q. What is included in Other Production Maintenance - Non-labor Expense?

A. The Other Production Maintenance - Non-labor Expense consists primarily of total costs for materials, contract services, and transportation to maintain HECO's 14 steam units, two combustion turbines, and associated infrastructure. In addition, a relatively small portion, approximately 10% of the outside service costs to maintain the 18 DG units is included in the Other Production Maintenance – Non-labor Expense.

Q. How is the Other Production Maintenance - Non-labor Expense forecast for the four maintenance groups?

A. The Other Production Maintenance - Non-labor Expense in the three Station Maintenance groups are forecast based on identifying specific discretionary and non-discretionary work, and trended routine work. The Non-labor expenses for the Travel Maintenance group are forecasted based on the 2007 Planned Maintenance Schedule (HECO-608) where known requirements are identified and forecasted. Other factors are considered in the development of the forecast include trended cost for particular items, level of outside service support to supplement labor; special tests and inspections by industry experts, and the estimated costs of long lead items.

Q. How does the 2007 test year Other Production Maintenance - Non-labor Expense of $23,891,000 compare with the 2005 recorded amount of $24,151,000?

A. The 2007 test year forecast of Other Production Maintenance - Non-Labor Expense is lower than 2005 recorded expenses by $260,000, or 1%, as shown on HECO-623.

Q. What is the decrease attributed to?

A. HECO-630 shows the breakdown of the 2005 recorded versus the test year 2007 variance of $260,000. The decrease is attributed to the net of variances in the expense categories consisting of material, outside services, transportation, and labor related on-cost. As explained in more detail below, there is a significant increase in outside services expenses of $1,380,000 that is offset by a significant decrease in materials costs of $1,516,000.

Q. Referring to HECO-630, please provide an explanation for the Other Production Maintenance – Non-labor variances by expense category.

A. Other Production Maintenance – Non-labor differences between 2005 Recorded and 2007 test year are provided below:

- <u>Material</u> – There is a decrease of $1,516,000 for maintenance non-labor material expenses that is mainly attributed actual expenses in 2005 being higher than anticipated. As shown in HECO-618, (HECO-626 for the 2005 test year), the maintenance non-labor material expense was forecast to be $6,427,000, but as shown in HECO-630 the 2005 actual expense was $9,254,000, or $2,827,000 higher than forecast. This difference was primarily due to increased material costs for station maintenance at Waiau Power Plant and Kahe Power Plant. The increased costs resulted from unanticipated repairs and unscheduled outages. The 2005 actual material costs for station maintenance at Honolulu Power Plant and for Travel Maintenance (i.e., overhauls and projects) were approximately equivalent to the 2005 test year estimate. A comparison 2007 test year estimate for maintenance non-labor material expense is actually $1,311,000 higher than the 2005 test year estimate for maintenance non-labor material expense.

- Outside Services – There is an increase of $1,380,000 for maintenance non-labor outside service expenses for the 2007 test year estimate compared to 2005 actual expenses. This increase offsets the decrease in maintenance non-labor material expense discussed immediately above in my testimony. After applying the adjustments and normalizations shown in HECO-625, the increase is reduced to $782,000. The higher maintenance non-labor outside services expenditure is attributable to several factors, including: escalated prices for outside services in the competitive labor market, the need to support concurrent scheduled and unscheduled maintenance activities, increased number of failures due to wear and tear on the aging equipment, and infrastructure maintenance. Also included in the maintenance non-labor outside service expense is the cost for Smart Signal (which is discussed in my testimony below). Also included in the maintenance non-labor outside service expense is the cost for infrastructure maintenance programs occurring in 2007, such as: Kahe Fuel Tank 11 Clean and Inspection; and the Kahe Sludge Bed Cleaning.
- Transportation – The $49,000 increase in non-labor transportation expenses is mainly attributed to increases in vehicle and transportation expenses.

- Labor-related on-cost – Labor-related on-cost is captured as a Non-labor expense and is comprised of Energy Delivery on-cost, and Power Supply on-cost. The $425,000 increase in non-labor on-cost expenses is primarily due to the increase in staffing levels in Power Supply Maintenance.

Q. What is Smart Signal?

A. Smart Signal is a computer-based technology that continuously monitors the operational parameters on equipment systems in the power plants and provides early detection of incipient equipment failure.

Q. Please describe the impact of Smart Signal on the Other Production O&M Expense.

A. Smart Signal would be installed across the HECO generating fleet in 2007 for $897,000. The cost would be amortized over three years so that the annual cost for 2007 would be $299,000.

Q. Please provide a summary and comments on variances of greater than $200,000 and 10% in Other Production Maintenance expenses between the actual 2005 and 2007 test year estimate expenses.

A. A summary variances of greater than $200,000 and 10% in Other Production Maintenance expenses between the actual 2005 and 2007 is provided in HECO-WP-601. As can readily be observed by a review of this work paper, it is not meaningful to discuss the variances by project. In general, this is because major maintenance work (overhauls and maintenance outages) were performed on different generating units in 2005 and 2007. Nevertheless, the HECO-WP-601 provides remarks to provide clarification for the observed variances.

Summary of Other Production Maintenance Expense

Q. Is HECO's estimate of the test year 2007 Other Production Maintenance Expense reasonable?

A. Yes. The estimate is reasonable because it was derived from a review of the work required to maintain reliability and availability of HECO's generating units and facilities. As explained earlier in my testimony, the maintenance staff, outside services, and materials are needed to perform the work necessary to sustain the performance and reliability of HECO generating units at acceptable levels.

PRODUCTION MATERIALS INVENTORY

Q. What is the Production Materials Inventory amount for test year 2007?

A. The Production Materials Inventory is $6,381,000 for the 2006 year-end inventory, and $6,886,000 for the year-end 2007. The 12-month average of the Production Stores Inventory for test year 2007 is $6,989,000. These amounts are shown on HECO-603.

Q. What is included in the Production Materials Inventory?

A. The Production Materials Inventory includes material stock such as spare parts for pumps, turbines, generators, and boilers.

Q. Why does HECO maintain a Production Materials Inventory?

A. Most parts are purchased from mainland suppliers and take from one week to over a year for delivery. The spare parts are needed to maintain unit availability, reliability and operating efficiency.

Q. How was the Production Materials Inventory amount determined for test year 2007?

A. The Production Materials Inventory amount for test year 2007 was determined by the following steps:

1) The starting point for calculations was recorded inventory values, receipts, and issues through September 30, 2006.
2) Receipts and issues were projected for the last three months of 2006, based on the 12 month average up to September 30, 2006.
3) The projected receipts and issues were added and subtracted, respectively, to the September 30, 2006 recorded inventory to obtain the estimated 2006 year end inventory value of $6,381,000.
4) 2007 projected issues was assumed to increase 12.2% over 2006, the average increase in issues from 2001 to 2005.
5) 2007 projected receipts was assumed to increase by 9.5% over 2007 projected issues, the average increase in issues from 2001 to 2005.
6) The 2007 projected receipts and 2007 projected issues were added and subtracted, respectively, to the projected 2006 year end inventory to estimate the 2007 test year year-end inventory amount of $6,886,000.
7) A projected turn ratio of 0.76, based on a review of recent trends in turn ratio, was used to derive the 2007 test year average inventory of $6,989,000.

Q. How did the value of Production Materials Inventory vary over the past years?

A. The value of the year-end stock balances increased from $4,011,000 to $6,165,000 between year-end 2001 and year-end 2005, as shown on HECO-603.

Q. Why is the test year 2007 Production Materials Inventory reasonable for ratemaking purposes?

A. The Production Materials Inventory is reasonable because it was derived from historical trends and the need to maintain an inventory to support both new and original equipment/designs currently in service.

SUMMARY

Q. Mr. Giovanni, please summarize your testimony.

A. HECO's test year 2007 Other Production Expense is estimated to be $68,222,000 after factoring in budget and normalization adjustments. The test year forecast is reasonable because it reflects a normal and adequate level of spend to operate and maintain the Company's generating plants at acceptable levels of performance and reliability. As mentioned throughout my testimony, all generating units on the Oahu system including IPPs are getting older and continue to experience operating duties that exert wear and tear on the equipment. HECO's baseload units are operating at high load factors and its cycling units are operating more hours. To operate all the units 24 X 7, provide the requisite personnel training, perform the necessary planned and unplanned maintenance, and provide the additional peaking capacity (i.e., 18 DG units) results in $11,093,000 higher Other Production O&M Expense in 2007 as compared to 2005. In addition, HECO's 12-month average Production Materials Inventory is estimated to be $6,989,000. This level of inventory is necessary to store sufficient spare parts and materials to maintain unit availability, reliability and efficiency.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

DAN V. GIOVANNI

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway, Pearl City, HI 96782
POSITION:	Manager, Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc. (HECO) (March 2006 to present)
PRIOR POSITION:	Manager, Production Department Hawaii Electric Light Company, Inc. (HELCO) (2001 to 2006)
YEARS OF SERVICE:	5 Years
EDUCATION:	University of California, Berkeley, B.S. Mechanical Engineering, 1970 University of California, Berkeley, M.S. Mechanical Engineering, 1971
EXPERIENCE:	President Electric Power Technologies, Inc. (EPT) (California, New York, and Hawaii) (1982 to 2001) Program Manager, Air Quality Control Electric Power Research Institute (EPRI) (1978 to 1982) Research Section Manager Kaiser Aluminum and Chemical Corporation (1975 to 1978) Consulting Engineer KVB Incorporated 1971 to 1975
PREVIOUS TESTIMONIES:	Docket No. 05-0315-Production Other O&M Expense Board of Land and Natural Resources Land Use Commission, State of Hawaii, Keahole Rezoning, 2005

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION O&M EXPENSE
($ Thousands)

		(A) 2007 TEST YEAR ESTIMATE
1	Operations Expense	$ 29,112
2	Maintenance Expense	$ 39,110
3	TOTAL OTHER PRODUCTION O&M EXPENSE	$ 68,222

Source: HECO-602

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION
OPERATIONS & MAINTENANCE EXPENSE
($ Thousands)

	(A) OPERATING BUDGET	(B) BUDGET ADJ	(C) NORMAL-IZATION	(D) 2007 TY ESTIMATE
OTHER PROD OPERATIONS EXPENSE				
1 Labor	$ 14,242	$ -	$ -	$ 14,242
2 Non-Labor	$ 15,483	$ (392)	$ (221)	$ 14,870
3 TOTAL	$ 29,725	$ (392)	$ (221)	$ 29,112
OTHER PROD MAINTENANCE EXPENSE				
4 Labor	$ 15,219	$ -	$ -	$ 15,219
5 Non-Labor	$ 24,489		$ (598)	$ 23,891
6 TOTAL	$ 39,708	$ -	$ (598)	$ 39,110
7 TOTAL PRODUCTION O&M EXPENSE	$ 69,433	$ (392)	$ (819)	$ 68,222

Source:
HECO-WP-101(A), page 2, for Column A.
HECO-624 for Column B.
HECO-625 for Column C.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

PRODUCTION MATERIAL INVENTORY
($ Thousands)

		RECORDED					2006 FORECAST	2007 TEST YEAR	2005 vs 2007	
		(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) 2006	(G) 2007	(H=G-E) $	(I=H/E) %
1	Year-End Value	4,010,686	4,439,987	4,797,614	5,488,941	6,165,365	6,380,537	6,886,142	720,777	12
2	Average Value	4,067,891	4,395,752	4,899,829	5,336,052	5,967,972	6,266,777	6,988,532	1,020,560	17
3	Total Issues	2,849,373	3,383,328	3,868,416	3,937,500	4,483,024	4,734,636	5,311,284	828,260	18
4	Annual Turnover Ratio	0.70	0.77	0.79	0.77	0.79	0.74	0.76		

Source: Col (A) through (C) -- HECO-628, Docket No. 04-0113.
Col (D) through (G) -- HECO-WP-602.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

Age of Generating Units
(as of 2006)

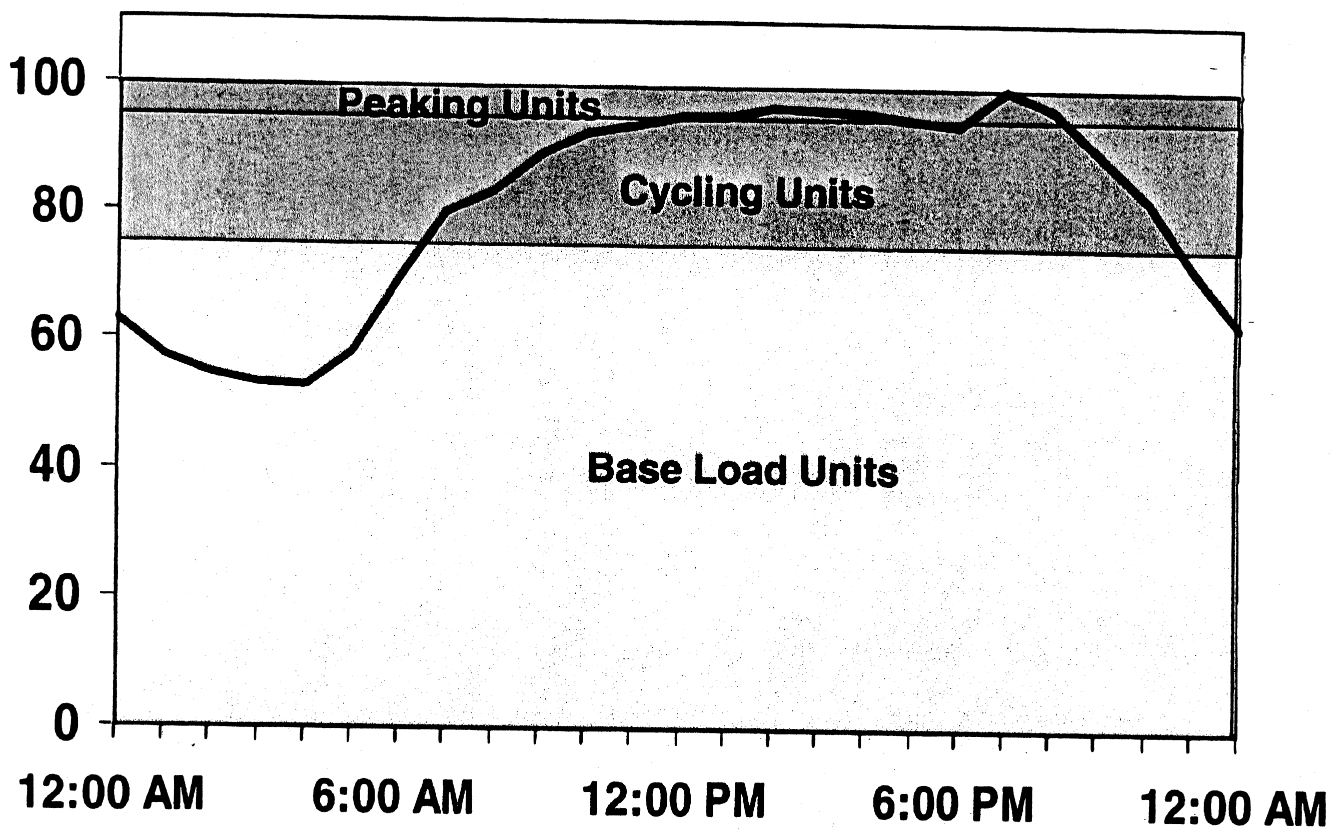
Unit	Capability (MW*)	Type	Operating Mode	Service Date	Age
HECO Generating Units					
Honolulu 8	56	Steam, Non-Reheat	Cycling	1954	52
Honolulu 9	57	Steam, Non-Reheat	Cycling	1957	49
Waiau 3	49	Steam, Non-Reheat	Cycling	1947	59
Waiau 4	49	Steam, Non-Reheat	Cycling	1950	56
Waiau 5	57	Steam, Non-Reheat	Cycling	1959	47
Waiau 6	56	Steam, Non-Reheat	Cycling	1961	45
Waiau 7	92	Steam, Reheat	Base	1966	40
Waiau 8	94	Steam, Reheat	Base	1968	38
Waiau 9	53	Combustion Turbine	Peaking	1973	33
Waiau 10	50	Combustion Turbine	Peaking	1973	33
Kahe 1	92	Steam, Reheat	Base	1963	43
Kahe 2	89	Steam, Reheat	Base	1964	42
Kahe 3	92	Steam, Reheat	Base	1970	36
Kahe 4	93	Steam, Reheat	Base	1972	34
Kahe 5	142	Steam, Reheat	Base	1974	32
Kahe 6	142	Steam, Reheat	Base	1981	25
HECO Distributed Generators					
Ewa Nui Sub Sta 1/2/3	5	Diesel Engine	Peaking	2005	1
Helemano Sub Sta 1/2/3	5	Diesel Engine	Peaking	2005	1
Iwilei Tank Farm 1/2/3	5	Diesel Engine	Peaking	2005	1
CEIP Sub Sta 1/2/3	5	Diesel Engine	Peaking	2006	0
Kalaeloa Pole Yard 1/2/3	5	Diesel Engine	Peaking	2006	0
Ewa Nui Sub Sta 4/5/6	5	Diesel Engine	Peaking	2007	0
Major Independent Power Producers					
HPOWER	46	Steam, Non-Reheat	Base	1990	16
Kalaeloa	208	Combined Cycle	Base	1991	15
AES	180	Steam, Reheat	Base	1992	14

Average age of HECO Steam Units	**42.7 Years**
Average age of HECO Reheat Steam Units	**36.3 Years**
Average age of HECO Non-Reheat Steam Units	**51.3 Years**
Average age of Independent Power Producers	**15.0 Years**

* HECO units in Gross megawatts; IPP units in Net megawatts.

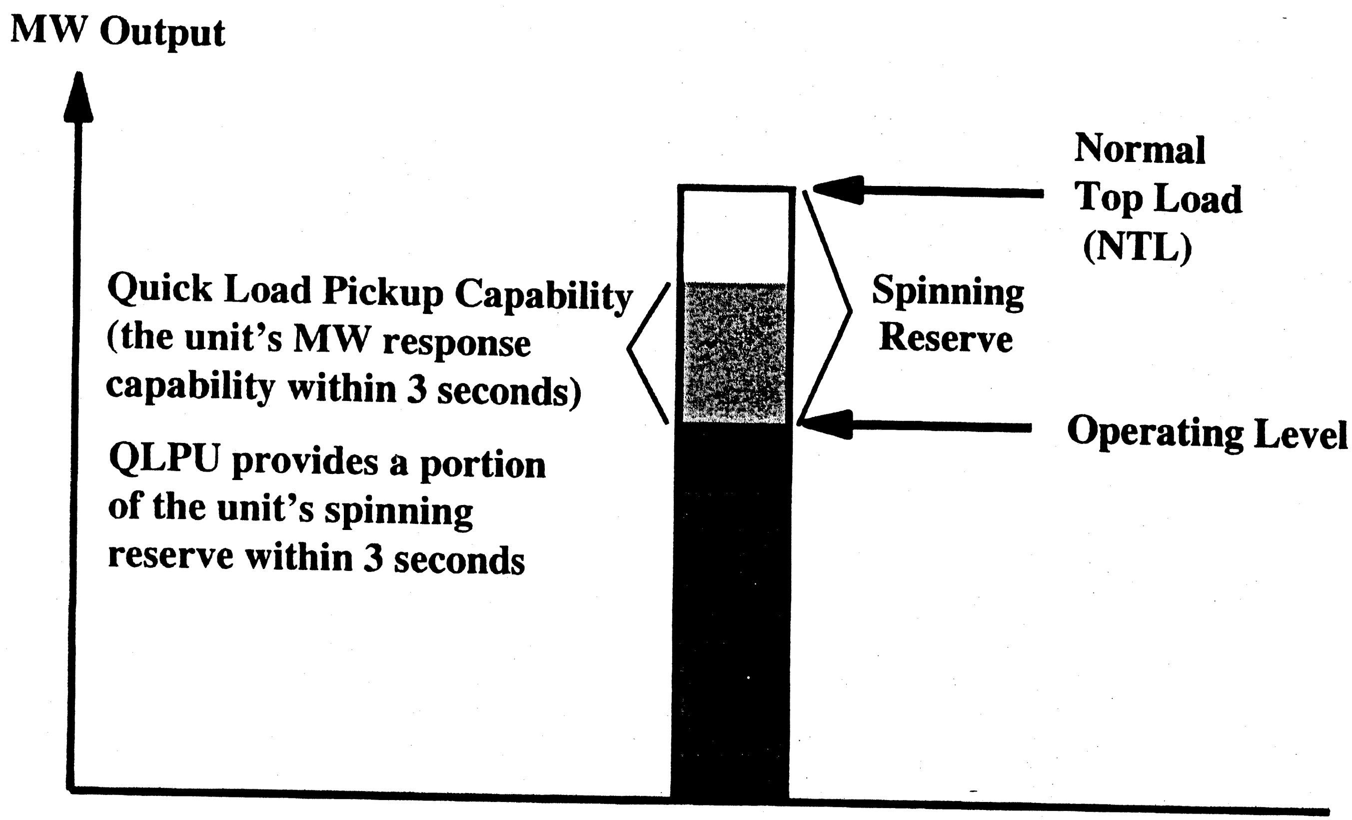
Hawaiian Electric Company, Inc.
2007 Test Year

Typical Daily Load Profile



Hawaiian Electric Company, Inc.
2007 Test Year

Relationship of Spinning Reserve and Quick Load Pickup Capability to Unit Capacity



Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

William A. Bonnet
Vice President
Government & Community Affairs

October 20, 2006

FILED

2006 OCT 20 P 1:23

PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Chairman Caliboso:

Subject: Report on Review of HECO's Power Supply Operations, Maintenance and Outage Management Programs by EPRI Solutions, Inc.

Enclosed for the Commission's information is a report prepared by the consultant EPRI Solutions, Inc ("ESI") on its review of Hawaiian Electric Company, Inc.'s ("HECO") Power Supply operations, maintenance and outage management programs (i.e., our practices, processes and policies).

Background

As part of a preliminary discussion of our Adequacy of Supply (AOS) situation for 2006 with the Commission and Consumer Advocate on February 24, 2006, we provided historical and forward-looking information regarding (1) maintenance and planned outages, effective forced outage rates and equivalent availability factors for HECO and firm IPP generating units providing power to our system, and other planning assumptions and forecasts (such as the peak load forecast, and projected CHP, energy efficiency DSM and load management DSM impacts on peak loads), (2) the impact of such information on HECO's projected reserve margin shortfall, and (3) actions being taken to mitigate the reserve margin situation.

As indicated in that discussion, and in the 2006 AOS Report submitted March 6, 2006, HECO anticipated reserve capacity shortfalls in 2006 and projected that these shortfalls will continue at least until 2009, which is the earliest that HECO expects to be able to permit, acquire, install and place into commercial operation its next central station generating unit. Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages, and more frequent, longer duration reserve capacity shortfalls. HECO has taken a number of actions to minimize the risk of generation-related shortfalls including initiatives to improve the availability and reliability of HECO's generating units.

As part of these efforts, HECO asked ESI to review HECO's Power Supply operations, maintenance and outage management programs (i.e., our practices, processes and policies) from an objective viewpoint and help us identify other candidate actions with the potential to improve generation availability and reliability. At the February 24, 2006 discussion with the Commission and Consumer Advocate, we indicated that we would provide the ESI report to the Commission and the Consumer Advocate when it was finalized.

Scope of ESI Review

The scope of the ESI review included the following:

1. Review the circumstances that contribute to the current situation such as decreasing reserve margins, condition of the generating fleet including independent power producers ("IPPs"), and human factors such as decreasing work force experience due to employee retirements,
2. Conduct a benchmarking study comparing HECO unit and fleet performance with mainland counterparts,
3. Review operations and maintenance practices,
4. Conduct plant personnel interviews, and
5. Identify candidate actions with the potential to improve generation availability and reliability.

Summary of Findings

ESI presented the following general observations based on its review:

1. On a comparative basis, HECO has been performing well. HECO is getting significantly more from its existing units than its industry peers;
2. As system demand has grown, HECO has experienced lower reserve margins;
3. A combination of factors has contributed to a deterioration of Equivalent Availability Factor (EAF) in recent years which may result in a decline of reliable service; and
4. Requirements for high capacity factors and extensive maintenance have made it difficult for HECO to sustain the high EAF achieved in the past.

ESI identified 26 candidate actions for consideration by HECO relative to their potential to improve HECO's generation availability and reliability. These candidate actions were divided into five groups:

1. Scheduled overhauls and outages,
2. Corrective and preventive maintenance,
3. Organization,
4. Technology application and data analysis, and
5. Training.

Overall, HECO is in agreement with the findings of the ESI report and agrees that the candidate actions presented by ESI represent opportunities to improve the availability and reliability of HECO's generation. For many of the candidate actions, HECO already has in place programs and projects to address the candidate actions, or these programs and projects are in the process of being implemented.

The following sections provide information on selected candidate actions from each of the five groups listed above, and a brief description of HECO's projects and programs that address these candidate actions.

1. Scheduled Overhauls and Outages

This group of nine candidate actions focused on improving the planning and implementation of overhauls. The primary driver is the benefit to be gained by shortening the duration of overhauls. Specific actions include establishing an outage manager position, improving the documentation of the work done during overhauls and conducting formal "lessons learned" sessions at the end of each overhaul.

Establish Outage Manager Position

A reorganization of the Power Supply Operations and Maintenance Department (PSO&M) in June 2006 included creation of a new position (Senior Supervisor, Overhauls) and the position has been filled. This person will fulfill the role of an Outage Manager. Please see Attachment A to this letter for more information on the June 2006 reorganization of the PSO&M Department.

Improve documentation of the work done during overhauls

The PSO&M Maintenance Superintendent has been tasked with implementing processes as necessary to improve documentation of work performed.

Conduct formal "lessons learned" sessions at the end of each overhaul

The Senior Supervisor, Overhauls has been designated as accountable for the turnover of information following overhauls.

2. Corrective and Preventative Maintenance

There were six candidate actions presented to improve the Power Supply Reliability Optimization ("PSRO") program. Specific candidate actions include placing a higher priority on performing routine preventative maintenance, improving the prioritization process for new work, and having the operators perform routine maintenance tasks.

Place higher priority on performing routine preventive maintenance
As part of the PSO&M reorganization of June 2006, the Predictive Maintenance ("PdM") group has been fortified with additional O&M Engineers and the role of the PdM group in the maintenance planning processes has been elevated.

Improve the prioritization process for new work
Preliminary review by HECO of work orders indicates that the high volume of high priority work orders is accurate. The Operations Division is taking a more active role in prioritizing the work on a more consistent basis at all three power plants.

Have operators perform routine maintenance tasks
HECO operators are performing many critical inspections and monitoring performance of the equipment.

3. Organization

The three candidate actions in this group focused on increasing management presence in the power plants. One candidate action is to evaluate the need for plant managers or empower the senior supervisors to provide leadership at each plant. Another candidate action is to establish a work group to review equivalent forced outage rate ("EFOR") incidents on a quarterly basis and to recommend appropriate actions.

Evaluate the need for plant managers or empower the Senior Supervisors
The PSO&M reorganization of June 2006 included re-establishment of Station Superintendents at the Kahe and Waiau/Honolulu Power Plants. The Senior Supervisor at each plant will be more focused on plant operations, development of shift supervisors, and administrative matters. The new Station Superintendent positions have been filled.

Establish a work group to review EFOR incidents on a quarterly basis and to recommend appropriate actions.
A formal root cause analysis ("RCA") program ("Taproot") has been launched. It will be targeted to major, recurring problems that adversely affect EFOR and EAF. EFOR and EAF are being tracked daily. PSO&M reviews results monthly. Major contributors to EFOR and EAF are identified and referred for RCA.

4. Technology Application and Analysis

The three candidate actions in this group focused on making better use of the currently available technologies and tools. This included both software tools and hardware tools.

Resolve software interface issues between the Ellipse software and other Maintenance Management System ("MMS")
Improvements to Ellipse (e.g., Emerson enhancement at HELCO) are being investigated. HECO is also increasing the use of the EPRI's PaSTA software tool for work scheduling.

Annually review North American Electric Reliability Council ("NERC") Generating Availability Data System ("GADS") data to benchmark HECO against industry peers.
NERC-GADS benchmarking can be used, in part, to assess the effectiveness of the PSO&M practices at a point in time, but not as a real-time guide for making daily decisions. System Owners prepare annual state of the system reports for the senior management team, and these reports help guide strategic planning for the PSO&M and PSED departments.

5. Training

The five candidate actions in the Training group focused on increased training throughout Power Supply. The target audiences for increased training included shift supervisors, operators, system owners and subject matter experts. Specific topics to be covered by the increased training included root cause analysis, commissioning of new equipment and systems, troubleshooting and maintenance planning.

Develop mentoring and training program for frontline supervisors and operators
The "team training" concept utilized by the US Navy is being adapted to utilize PSO&M's most knowledgeable personnel to mentor and train its less experience employees. This is a new, high priority assignment for the newly established position of Senior Supervisor for Training. This new position was established as part of the June 2006 reorganization of the PSO&M and has been filled. Again, for more information on the reorganization, please refer to Attachment A.

Implement a formal and structured root cause analysis methodology
A formal root cause analysis ("RCA") program has been launched. It will be targeted to major, recurring problems that adversely affect EFOR and EAF.

Improve troubleshooting capabilities.
As part of the PSO&M reorganization of June 2006, the O&M Engineers have been consolidated into a new, larger group. One of the primary responsibilities of this group will be to lead and support troubleshooting efforts.

As stated above, HECO is in agreement with the findings of the ESI report and agrees that the candidate actions presented by ESI represent opportunities to improve the availability and reliability of HECO's generation. For the majority of the candidate actions, HECO already has in place programs and projects to address the candidate actions. For the remainder of the candidate actions, HECO is implementing initiatives to address the candidate actions.

Thank you for the opportunity to presents this information. If you have any questions or need additional information, please contact me.

Very truly yours,

Enclosures

cc: Division of Consumer Advocacy (with Enclosure)

Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
02/14/06 rev.

An HEI Company

POWER SUPPLY OPERATION & MAINTENANCE
2007 PLANNED MAINTENANCE
SCHEDULE 6 YEAR CYCLE
Peaks as of: 5/1/2005
Revision date: 2/14/2006

Comments:
Approved 4-16-02
Revised 4-25-03
Approved 4-28-03
Revised 6-4-03
Approved 6-9-03
Revised 11-24-03
Revised 11-26-03 (new peaks)
Revised 1-7-04
Approved 1-12-04
Revised 9-9-04 KPLP
Revised 10-27-04
Approved 2-3-05
Approved 10-25-05[1]
Approved 11-23-05[2]

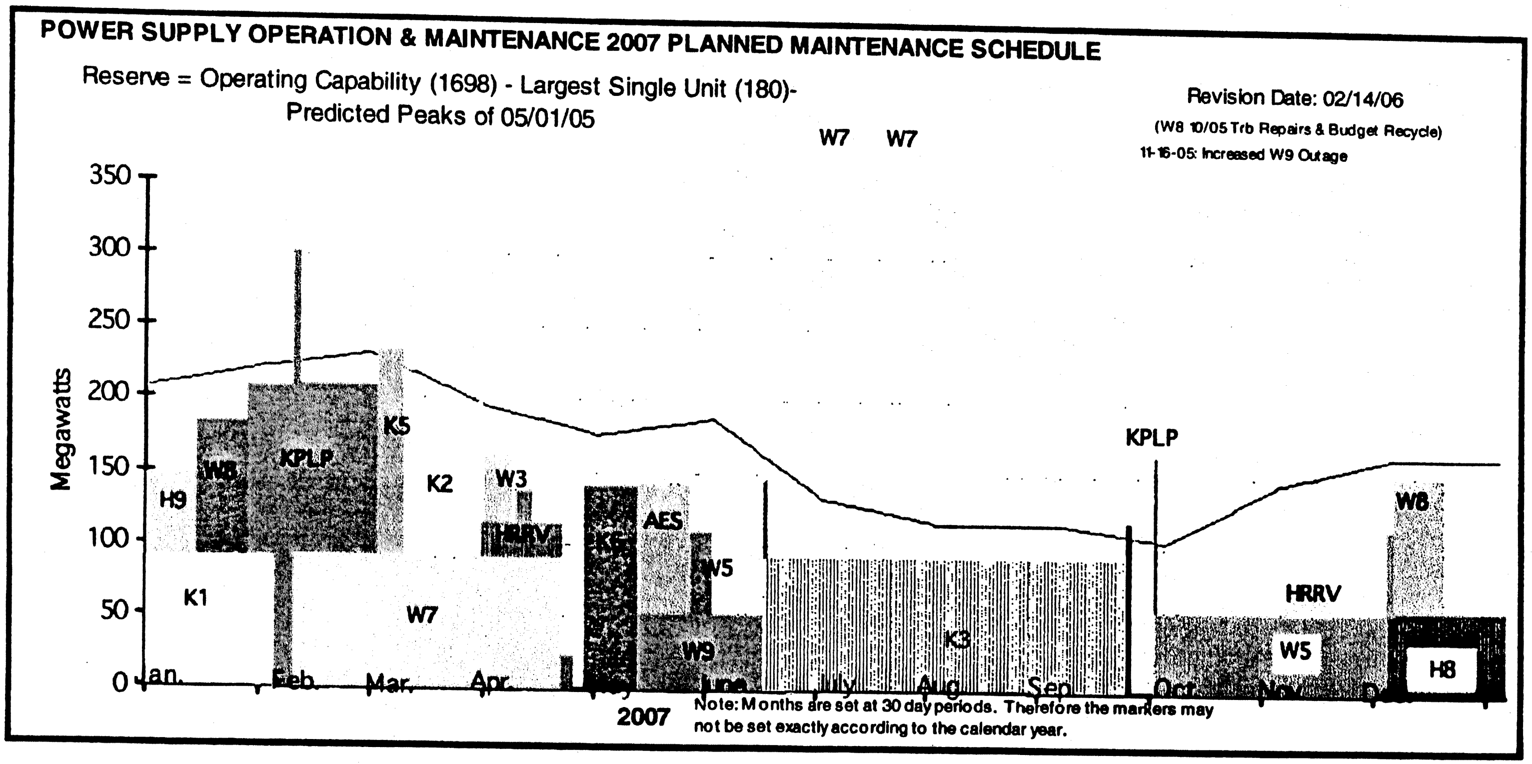
UNIT	DATE				Duration	REMARKS
	Brk Op	Start	Bkr Cl	Firm	(Wks.Days)	
H9	10/14/2006	10/16/2006	1/12/2007	1/13/2007	13.0	Outage (con't. from 2006)
K1	10/27/2006	10/30/2006	2/2/2007	2/3/2007	14.1	Overhaul (con't. from 2006)
W8	1/14/2007	1/15/2007	1/26/2007	1/27/2007	1.6	Tunnel Cleaning
KPLP-	1/28/2007		2/3/2007		1.0	104.5 MW Loss
KPLP	2/4/2007		2/10/2007		1.0	209 MW Loss
KPLP-	2/11/2007		3/3/2007		3.0	104.5 MW Loss
W7	2/9/2007	2/12/2007	4/20/2007	4/21/2007	10.1	Overhaul (Cond refurb, Exc/Reg, Annun, Tsf, HP/LP)
K5	3/4/2007	3/5/2007	3/9/2007	3/10/2007	0.6	Blr Inspection (exp 4/7/07)
K2	3/11/2007	3/12/2007	3/30/2007	3/31/2007	2.6	Maintenance Outage ()
HRRV-	3/31/2007		4/9/2007		1.3	23 MW Loss
HRRV	4/10/2007		4/13/2007		0.4	46 MW Loss
HRRV-	4/14/2007		4/24/2007		1.4	23 MW Loss
W3	4/1/2007	4/3/2007	4/7/2007	4/8/2007	1.0	Blr Inspection (exp 9/7/07)
K6	4/28/2007	4/30/2007	5/11/2007	5/12/2007	2.0	Blr Wash
W9	5/13/2007	5/14/2007	6/15/2007	6/16/2007	4.6	Combustion Inspection
AES-	5/13/2007		5/26/2007		2.0	90 MW Loss
W5	5/27/2007	5/28/2007	5/31/2007	6/1/2007	0.5	Blr Inspection (exp 8/2/07)
K3	6/16/2007	6/18/2007	9/14/2007	9/21/2007	13.0	Overhaul (Blr Ctrls, S/B Ctrls, Exc/Reg, Annun, HP/LP/Gen)
KPLP-	9/22/2007		9/22/2007		0.1	104.5MW Loss
W5	9/29/2007	10/1/2007	11/30/2007	12/1/2007	9.0	Overhaul (CCI, Exc/Reg, HP/LP, Chem Clng)
KPLP-	9/29/2007		9/29/2007		0.1	104.5 MW Loss
HRRV-	11/3/2007		11/15/2007		1.6	23 MW Loss
H8	11/30/2007	12/3/2007	2/8/2008	2/9/2008	10.1	Overhaul (Annun, Volt Reg, Sootblw Ctrls, TSI, Main Tsf, HP/LP)
W8	12/2/2007	12/3/2007	12/14/2007	12/15/2007	1.6	Tunnel Cleaning

Aaron Fujinaka
Power Supply O&M Manager

Date

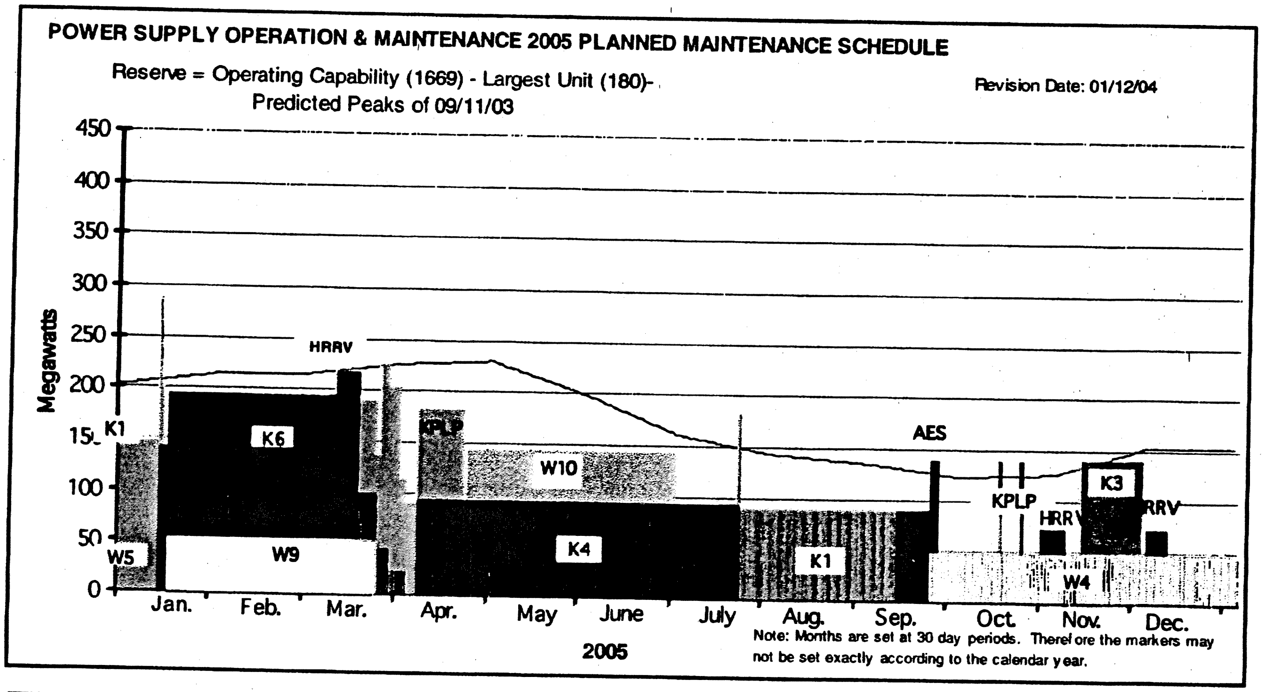
1. W8 10/05 Turbine Repairs & Budget Recycle.
2. Proposed - moved H9 Gen Rewind Outage (2006) back, to accommodate Lead Time for Exciter; adjusted OH durations; Corrected W9/W10 cycles.

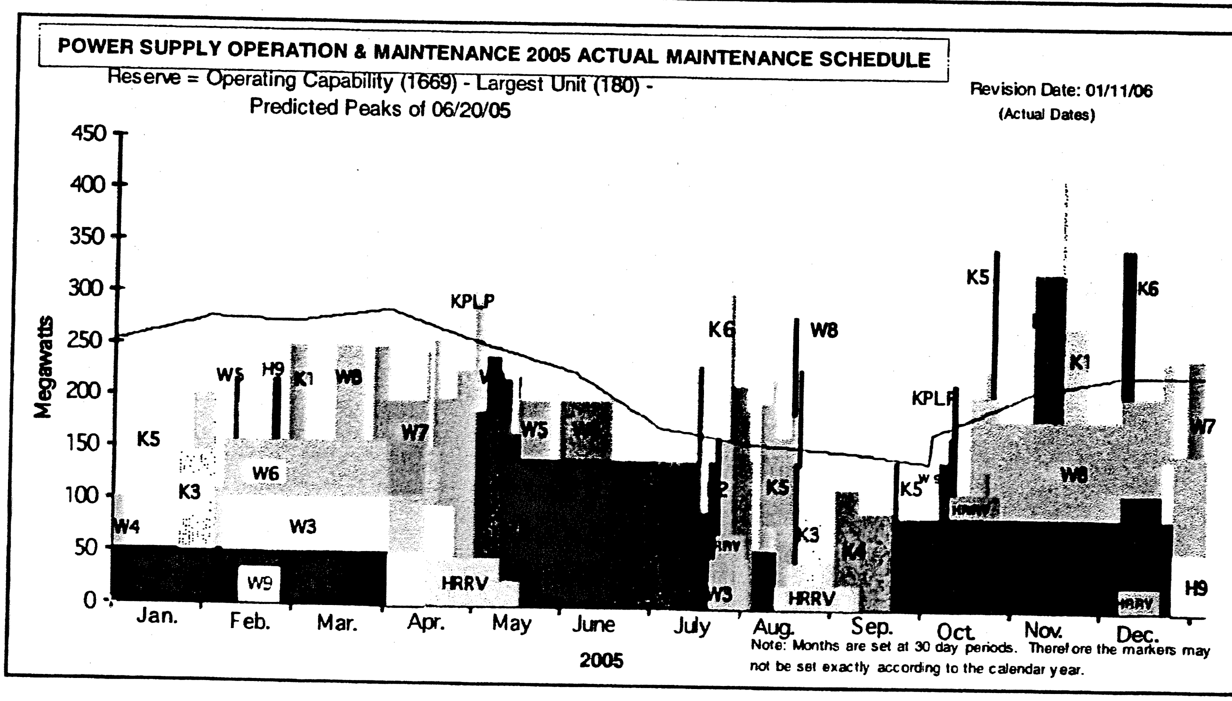
Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
02/14/06 rev.



Hawaiian Electric Company, Inc.
2007 Test Year

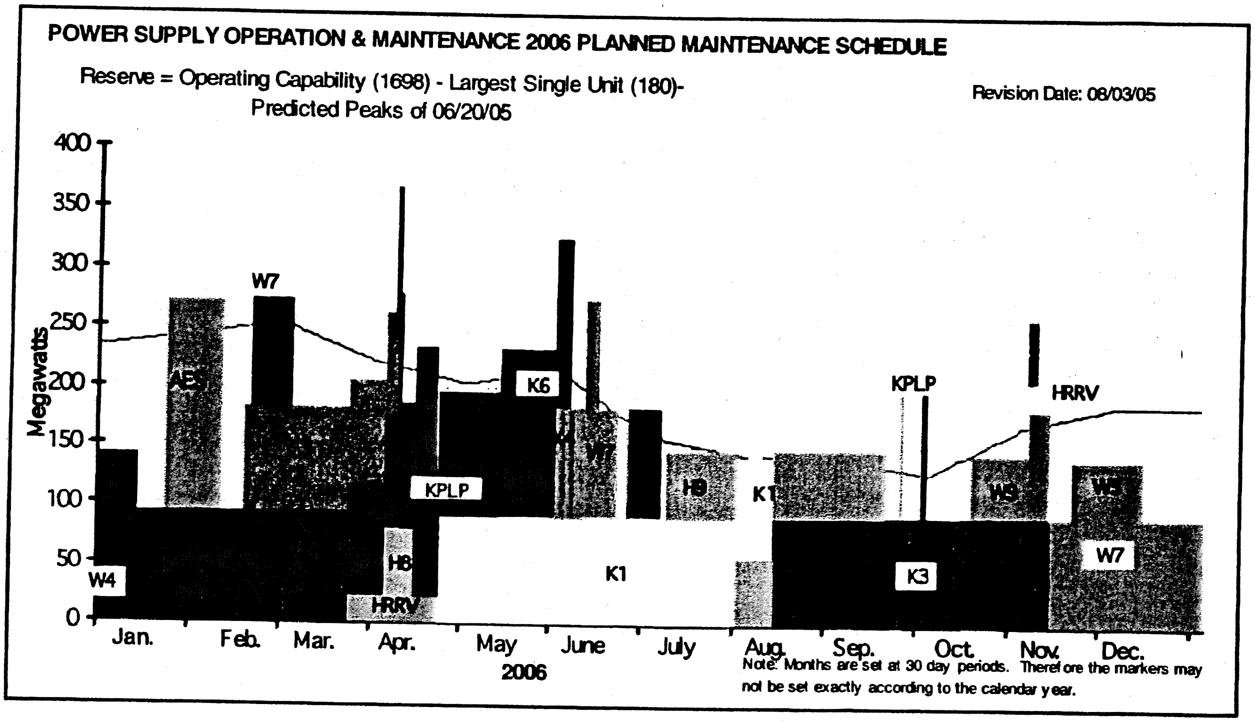
2005 Planned vs Actual Maintenance Schedule

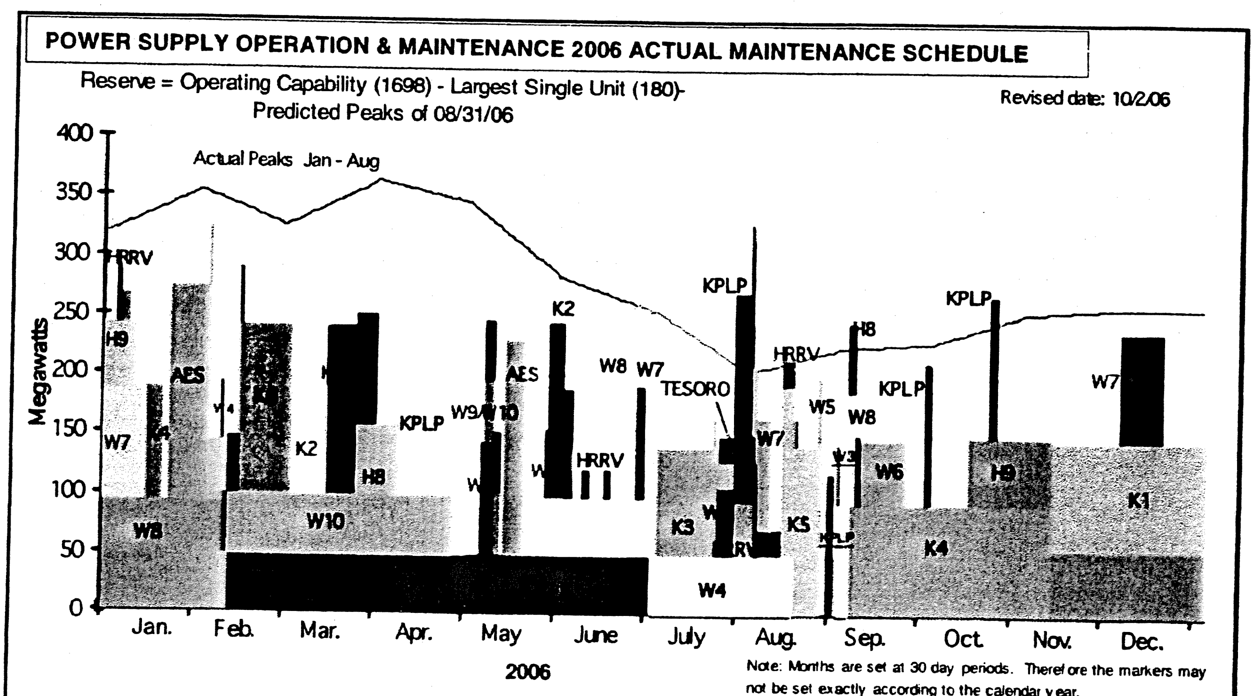




Hawaiian Electric Company, Inc.
2007 Test Year

2006 Planned vs Actual Maintenance Schedule





Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
07/21/06 rev.

An HEI Company

POWER SUPPLY OPERATION & MAINTENANCE
2007 PLANNED MAINTENANCE SCHEDULE

Peaks as of: 5/3/2006
Revision date: 7/21/2006

Comments:
Approved 4-16-02
Revised 4-25-03
Approved 4-28-03
Revised 6-4-03
Approved 6-9-03
Revised 11-24-03
Revised 11-26-03 (new peaks)
Revised 1-7-04
Approved 1-12-04
Revised 9-9-04 KPLP
Revised 10-27-04
Approved 2-3-05
Approved 10-25-05
Approved 11-23-05
Approved 7-21-06

UNIT	DATE				Duration	
	Brk Op	Start	Bkr Cl	Firm	(Wks.Days)	
H9	10/14/2006	10/16/2006	1/12/2007	1/13/2007	13.0	Generator Rewind Outage (con't. from 2006)
K1	11/4/2006	11/6/2006	2/9/2007	2/10/2007	14.0	Overhaul (con't. from 2006)
W8	1/14/2007	1/15/2007	1/26/2007	1/27/2007	1.6	Tunnel Cleaning, APH Wash
HRRV-	1/20/2007		2/4/2007		2.2	23 MW Loss
KPLP-	1/28/2007		2/13/2007		2.3	118 MW Loss (CT2)
KPLP	2/14/2007		2/22/2007		1.2	208 MW Loss
KPLP-	2/23/2007		3/3/2007		1.2	118 MW Loss (CT2)
W7	2/24/2007	2/26/2007	5/4/2007	5/5/2007	10.0	Overhaul (Cond refurb, Exc/Reg, S/B Ctrls, Tsf, HP/LP)
K2	3/11/2007	3/12/2007	3/30/2007	3/31/2007	2.6	Maintenance Outage, APH Wash, Tsf Bushing
W3	4/1/2007	4/2/2007	4/13/2007	4/14/2007	1.6	Blr Inspection (exp 9/7/07)
H8	4/15/2007	4/16/2007	4/27/2007	4/28/2007	1.6	Blr/APH Wash
W9	5/6/2007	5/7/2007	6/8/2007	6/9/2007	4.6	Overhaul - Combustion Inspection, Ovation
K5	5/6/2007	5/7/2007	5/25/2007	5/26/2007	2.6	Maintenance Outage (), ACW Lines
K6	5/27/2007	5/28/2007	6/7/2007	6/8/2007	1.5	Blr/APH Wash, ACW Lines
K3	6/9/2007	6/11/2007	9/7/2007	9/14/2007	13.0	Overhaul (Blr Ctrls, Exc/Reg, Annun, HP/LP/Gen)
W4	6/17/2007	6/18/2007	6/29/2007	6/30/2007	1.6	APH Wash/Inspection
HRRV-	7/14/2007		7/29/2007		2.2	23 MW Loss
W6	8/12/2007	8/13/2007	8/24/2007	8/25/2007	1.6	Tunnel Cleaning
W5	9/16/2007	9/17/2007	11/16/2007	11/17/2007	8.6	Overhaul (CCI, Exc/Reg, HP/LP, Chem Clng)
KPLP-	9/22/2007		9/22/2007		0.1	118 MW Loss
KPLP-	9/29/2007		9/29/2007		0.1	118 MW Loss
AES-	10/1/2007		10/16/2007		2.2	90 MW Loss
K4	10/20/2007	10/22/2007	11/2/2007	11/3/2007	2.0	Maintenance Outage ()
H9	11/4/2007	11/5/2007	11/16/2007	11/17/2007	1.6	Blr/APH Wash
W8	11/25/2007	11/26/2007	12/7/2007	12/8/2007	1.6	Tunnel Cleaning
H8	11/30/2007	12/3/2007	2/8/2008	2/9/2008	10.1	Overhaul (Annun, Volt Reg, SSH, TSI, Main Tsf, HP/LP)
W7	12/9/2007	12/10/2007	12/28/2007	12/29/2007	2.6	Tunnel Cleaning

Dan Giovanni
Power Supply O&M Manager

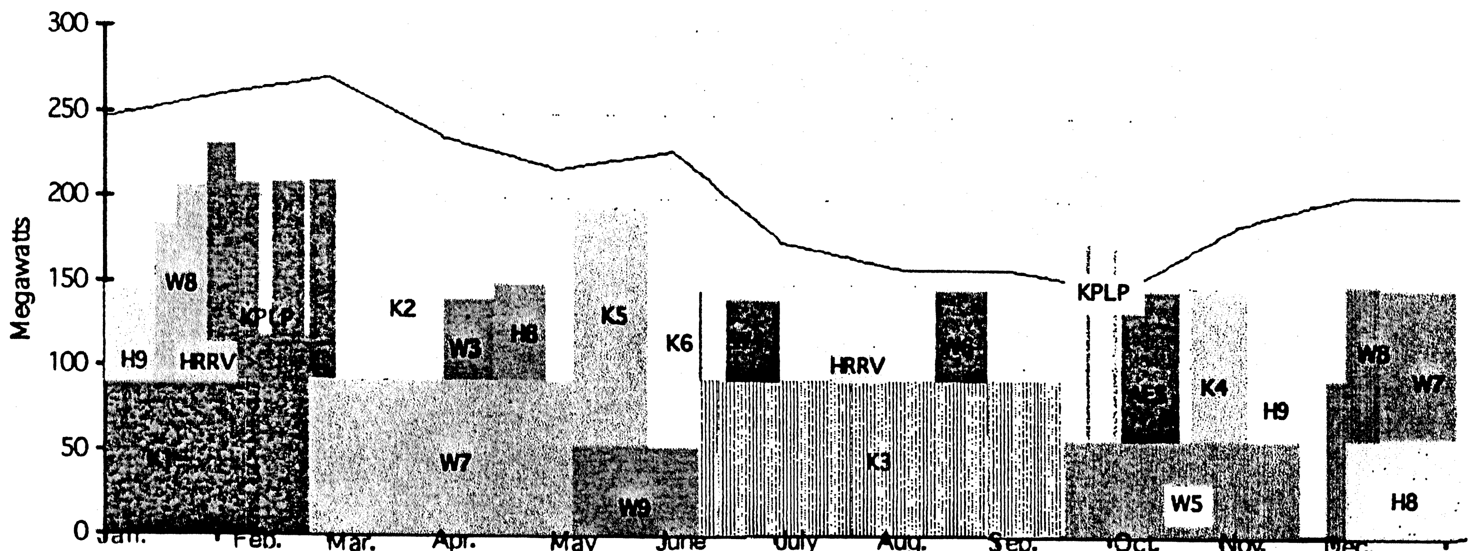
Date

Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
07/21/06 rev.

POWER SUPPLY OPERATION & MAINTENANCE 2007 PLANNED MAINTENANCE SCHEDULE

Reserve = Operating Capability (1698) - Largest Single Unit (180)-
Predicted Peaks of 05/03/06

Revision Date: 07/21/06



Note: Months are set at 30 day periods. Therefore the markers may not be set exactly according to the calendar year.

HECO-611
DOCKET NO. 2006-0386
PAGE 2 OF 2

Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
11/21/06 rev.

An HEI Company

POWER SUPPLY OPERATION & MAINTENANCE
2007 PLANNED MAINTENANCE SCHEDULE

Peaks as of: 8/31/2006
Revision date: 11/21/2006

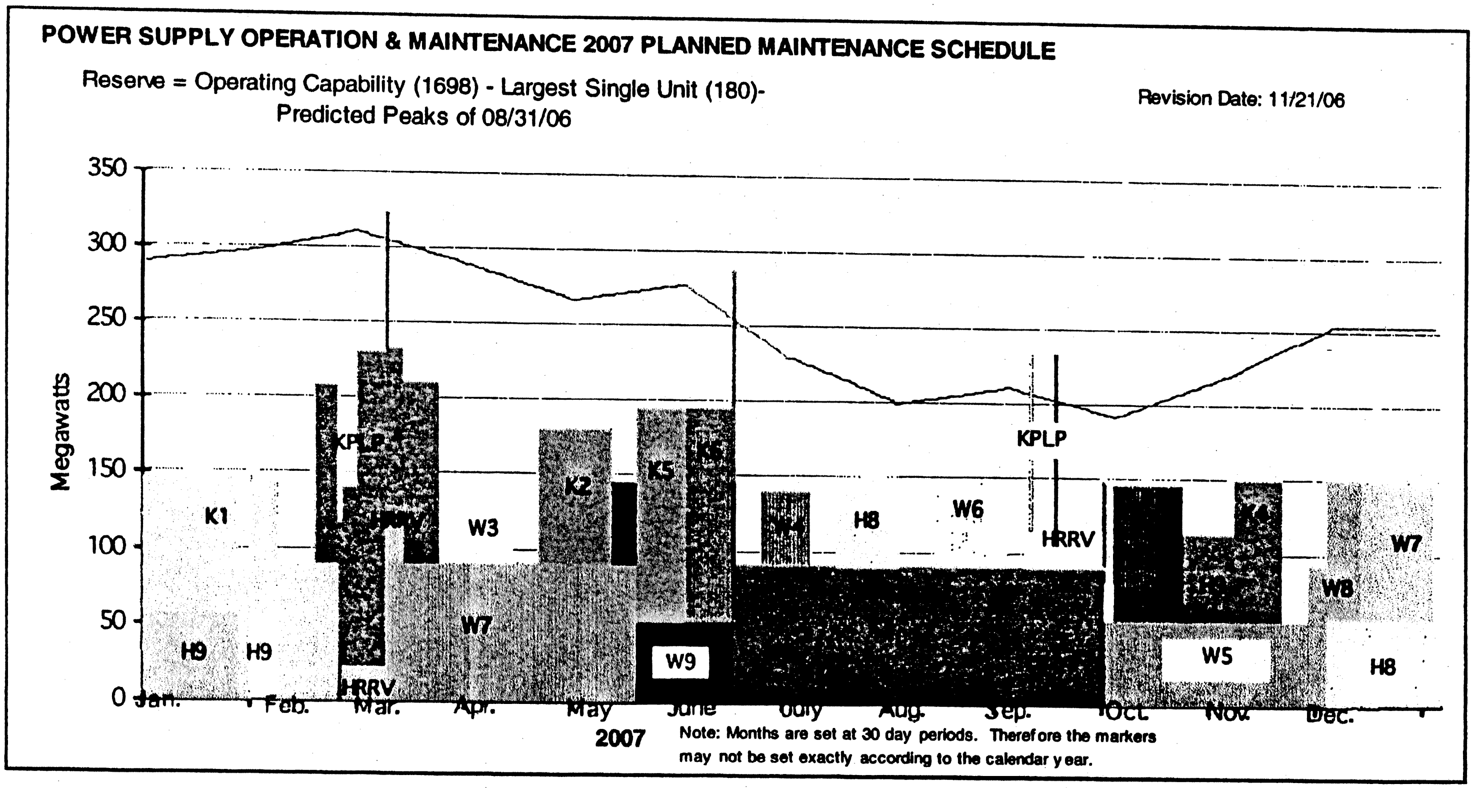
Comments:
Revised 1-7-04
Approved 1-12-04
Revised 9-9-04 KPLP
Revised 10-27-04
Approved 2-3-05
Approved 10-25-05
Approved 11-23-05
Approved 7-21-06
Revised 10-2-06
Approved 10-2-06
Revised 11-21-06
Approved 11-21-06

UNIT	DATE				Duration	REMARKS
	Brk Op	Start	Bkr Cl	Firm	(Wks.Days)	Remarks
H9	10/20/2006	10/20/2006	1/26/2007	1/27/2007	14.1	Generator Rewind Outage (con't. from 2006)
K1	11/24/2006	11/25/2006	2/23/2007	2/24/2007	13.1	Con't from '06 (annctr,MS p'png rpl,op console,excitation, RH, HP/LP)
H9	1/31/2007	2/1/2007	2/6/2007	2/7/2007	1.0	Remove throttle valve strainers (installed for SSH replacmt)
KPLP-	2/18/2007		3/1/2007		1.5	118 MW Loss (CT2)
KPLP	3/2/2007		3/10/2007		1.2	208 MW Loss
KPLP-	3/11/2007		3/24/2007		2.0	118 MW Loss (CT2)
HRRV-	2/26/2007		3/14/2007		2.3	23 MW Loss
W7	3/10/2007	3/12/2007	5/18/2007	5/19/2007	10.0	Overhaul (Cond refurb, Exc/Reg, S/B Ctrls, Tsf, HP/LP)
W3	3/25/2007	3/26/2007	4/13/2007	4/14/2007	2.6	Blr Inspection (exp 9/7/07)
K2	4/22/2007	4/23/2007	5/11/2007	5/12/2007	2.6	Maintenance Outage, APH Wash, Tsf Bushing
W9	5/13/2007	5/14/2007	6/16/2007	6/16/2007	5.0	Combustion Inspection, Ovation, rpl canon plugs/wiring
K5	5/20/2007	5/21/2007	6/1/2007	6/2/2007	1.6	Maintenance Outage (), ACW Lines
K6	6/3/2007	6/4/2007	6/15/2007	6/16/2007	1.6	Blr/APH Wash, ACW Lines
K3	6/16/2007	6/17/2007	9/14/2007	9/28/2007	13.0	OH(Blr Ctrls, Exc/Reg, Annun, HP/LP/Gen, 2 wks tsting, blr permit 1/26/08)
W4	6/24/2007	6/25/2007	7/6/2007	7/7/2007	1.6	APH Wash/Inspection
H8	7/15/2007	7/16/2007	7/31/2007	8/1/2007	2.3	Blr/APH Wash, Pre-OH maint
W6	8/12/2007	8/13/2007	8/31/2007	9/1/2007	2.6	Blr Insptn (permit exp 4/7/08), Tunnel Cleaning
HRRV-	9/7/2007		9/17/2007		1.4	23 MW Loss
HRRV	9/18/2007		9/23/2007		0.6	46 MW Loss
HRRV-	9/24/2007		9/30/2007		1.0	23 MW Loss
KPLP-	9/8/2007		9/8/2007		0.1	118 MW Loss
KPLP-	9/15/2007		9/15/2007		0.1	118 MW Loss
W5	9/28/2007	9/29/2007	11/23/2007	11/24/2007	8.1	Overhaul (CCI, Exc/Reg, HP/LP, Chem Clng)
AES-	10/1/2007		10/20/2007		2.6	90 MW Loss
H9	10/21/2007	10/22/2007	11/2/2007	11/3/2007	1.6	Blr/APH Wash
K4	11/4/2007	11/5/2007	11/16/2007	11/17/2007	1.6	Maintenance Outage ()
W8	11/25/2007	11/26/2007	12/7/2007	12/8/2007	1.6	Tunnel Cleaning, APH Wash, Aux Xfmer Flex Links
H8	11/30/2007	12/3/2007	2/8/2008	2/9/2008	10.1	Overhaul (Annun, Volt Reg, SSH, TSI, Main Tsf, HP/LP, Elec cables)
W7	12/9/2007	12/10/2007	12/28/2007	12/29/2007	2.6	Tunnel Cleaning, Blr APH Wash

Dan Giovanni
Power Supply O&M Manager

Date

Hawaiian Electric Company, Inc.
2007 Test Year
2007 Planned Maintenance Schedule
11/21/06 rev.



Hawaiian Electric Company, Inc.
2007 TEST YEAR

VP-POWER SUPPLY EMPLOYEE COUNT

		(A) 2004 RECORDED	(B) 2005 RECORDED	(C) 2006YTD (09/30/06)	(D) 2006 PROJECTED EOY	(E) 2007 TEST YEAR
	VP - POWER SUPPLY					
1	Environmental Department	24	22	22	22	24
2	Power Supply Engineering Department (formerly Planning & Engineering)	41	41	37	40	46
3	Power Supply O&M Department	296	299	306	314	352
4	Power Supply Services Department	32	30	29	29	31
5	VP-Power Supply's Office	2	2	2	2	2
6	TOTAL	395	394	396	407	455

Note: HECO-1403 provides 13-month average employee counts.

Hawaiian Electric Company, Inc.
2007 Rate Case - Power Supply Process Area
Filling of Vacancies in 2006 and 2007

Position	RA	2005 Actual	9/06 YTD Actual	2006 Oct	2006 Nov	2006 Dec	2006 TOT	2007 Jan	2007 Feb	2007 Mar	2007 Apr	2007 May	2007 Jun	2007 Jul	2007 Aug	2007 Sep	2007 Oct	2007 Nov	2007 Dec	2007 TOT	YTD 2007
ENVIRONMENTAL DEPT																					
ADMIN																					
Manager	JA	1	1				0													0	1
Sr. Environ Scientist	JA	1	1				0													0	1
Secretary	JA	1	1				0													0	1
Clerk Typist	JA	1	1				0													0	1
Admin Subtotal		4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Air Quality / Noise																					
Prin Environ Scientist	JB	1	1				0													0	1
Sr. Environ Scientist	JB	3	3				0		1											1	4
Environ Scientist	JB	1	1				0													0	1
Air Quality/Noise Subtotal		5	5	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	6
Chemistry																					
Lab Supervisor	JC	1	1				0													0	1
Analytical Chemist	JC	5	5				0													0	5
Chemistry Subtotal		6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Water & Hazardous Materials																					
Prin Environ Scientist	JW	1	1				0													0	1
Sr. Environ Scientist	JW	4	4				0													0	4
Environl Scientist	JW	1	1				0		1											1	2
Environl Specialist	JW	1	1				0													0	1
Water & Haz Mat Subtotal		7	7	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	8
TOTAL ENVIRONMENTAL		22	22	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	2	24
POWER SUPPLY ENGINEERING																					
ADMIN																					
Manager	YA	1	1				0													0	1
Secretary	YA	1	1				0													0	1
Administrator	YA	1	1				0													0	1
Admin Subtotal		3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Support Staff																					
Project Cleck	YC	1	1				0													0	1
Drawing Control Clerk	YC	1	1				0													0	1
Support Staff Subtotal		2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Technical Services																					
Superintendent	YE	1	1				0													0	1
Senior Staff Engineer	YE	5	5				0			1										1	6
Staff Engineer	YE	2	2	-1			-1		1											1	2
Technical Services Subtotal		8	8	-1	0	0	-1	0	1	1	0	0	0	0	0	0	0	0	0	2	9
Electrical Engineering Section																					
Sr. Supervising Engi	YF	1	1				0													0	1
Engineer II	YF	3	1		2		2	1		1										2	5
Engineer I (DesignerII)	YF	6	5	1			1													0	6
Electrical Eng Sec Subtotal		10	7	1	2	0	3	1	0	1	0	0	0	0	0	0	0	0	0	2	12
Drafting Section																					
Drafting Technician II	YG	2	2				0													0	2
Drafting Subtotal		2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Project Manangement																					
Project Manager	YJ	5	4	-1		2	1													0	5
Project Management Subtotal		5	4	-1	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	5

Hawaiian Electric Company, Inc.
2007 Rate Case - Power Supply Process Area
Filling of Vacancies in 2006 and 2007

Position	RA	2005 Actual	9/06 YTD Actual	2006 Oct	2006 Nov	2006 Dec	2006 TOT	2007 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2007 TOT	YTD 2007
Mechanical Engineering Section																					
Prin Eng, Power Plt Eng	YM	1	1				0													0	1
Sr. Supervising Eng	YM	1	1				0													0	1
Engineer II	YM	6	6				0	1	1											2	8
Engineer II (Designer II)	YM	3	3				0													0	3
Mechanical Eng Sec Subtotal		11	11	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	2	13
TOTAL POWER SUPPLY ENG		41	37	-1	2	2	3	2	2	2	0	0	0	0	0	0	0	0	0	6	46
POWER SUPPLY SERVICES DEPT																					
ADMIN																					
Power Supply Srvc Mngr	IA	1	1				0													0	1
Power Supply Srvc Secr	IA	1	1				0													0	1
Administrator	IA	1	1				0													0	1
Contracts Administrator	IA	1	0				0													0	0
Admin Subtotal		4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
POWER PURCHASE																					
Power Purchase Dir	IC	1	1				0													0	1
Power Purch Contr Adm	IC	3	3				0													0	3
Administrative Assistant	IC	2	2				0													0	2
Power Purchase Subtotal		6	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
FUELS RESOURCES																					
Fuel Resources Director	IF	1	1				0													0	1
Fuels Contracts Admin	IF	1	1				0		2											2	3
Fuels Records Clerk	IF	1	1				0													0	1
Forecast Plan Analyst	IF	1	1		-1		-1													0	0
Fuels Resources Subtotal		4	4	0	-1	0	-1	0	2	0	0	0	0	0	0	0	0	0	0	2	5
GENERATION PLANNING																					
Generation Planning Dir	YB	1	1				0													0	1
Sr Plannning Engineer	YB	3	3				0													0	3
Planning Engineer	YB	5	5	-1		1	0													0	5
Generation Planning Subtotal		9	9	-1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
TRANSMISSION PLANNING																					
Transm Planning Dir	YT	1	1			-1	-1	1												1	1
Lead Transm Plan Eng	YT	3	3				0													0	3
Transm Planning Eng	YT	3	3		1		1													0	4
Transmission Planning Subto		7	7	0	1	-1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	8
TOTAL POWER SUPPLY SERV		30	29	-1	0	0	-1	1	2	0	0	0	0	0	0	0	0	0	0	3	31
POWER SUPPLY O&M																					
ADMIN																					
Power Supply O&M Mngr	IB	1	1				0													0	1
Mgr Special Projects	IB	0	1				0												-1	-1	0
Power Supply O&M Sec	IB	1	1				0													0	1
Senior Technical Analyst	IB	0	1				0													0	1
Budget Analyst	IB	1	1				0													0	1
Technical Trainer	IB	1	0				0													0	0
Environmental Specialist	IB	0	0				0		1											1	1
Env Compliance Superv	IB	1	1				0													0	1
Station Chemist	IB	2	2				0													0	2
Admin Subtotal		7	8	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	-1	0	8
TRAINING																					
Senior Supv. Trainer	ID	0	1				0													0	1
Technical Trainer	ID	0	1				0		1											1	2
Training Subtotal		0	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	3

Hawaiian Electric Company, Inc.
2007 Rate Case - Power Supply Process Area
Filling of Vacancies in 2006 and 2007

Position	RA	2005 Actual	9/06 YTD Actual	2006 Oct	2006 Nov	2006 Dec	2006 TOT	2007 Jan	2007 Feb	2007 Mar	2007 Apr	2007 May	2007 Jun	2007 Jul	2007 Aug	2007 Sep	2007 Oct	2007 Nov	2007 Dec	2007 TOT	YTD 2007
OPERATIONS																					
Honolulu Senior Superv	IH	1	1				0													0	1
Shift Supervisor	IH	4	5				0													0	5
Honolulu Operators	IH	21	20				0		2	-1										1	21
Kahe Senior Shift Suprv	IK	1	1				0													0	1
Kahe Station Aide	IK	1	1				0													0	1
Shift Supervisor	IK	7	6		-1	2	1													0	7
Kahe Operators	IK	49	48	2			2		2											2	52
Operation Superint	IO	1	2				0													0	2
Operation Pwr Eng	IO	1	0				0													0	0
Waiau Sr Shift Super	IW	1	1				0													0	1
Waiau Station Aide	IW	1	1				0													0	1
Shift Supervisor	IW	7	6		1		1													0	7
Waiau Operators	IW	49	52		0		0		4				1							5	57
Operations Subtotal		**144**	**144**	**2**	**0**	**2**	**4**	**0**	**8**	**-1**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**8**	**156**
PLANNING																					
Planning & Eng Super	IP	1	1				0													0	1
Power Plant Clerk	IP	1	1				0													0	1
Senior Supervisor	IP	1	2				0													0	2
Work Management Spec	IP	0	0				0		1											1	1
Resource Planner	IP	8	7			-1	-1	2	2											4	10
Planning/Project Coord	IP	1	1				0	-1												-1	0
O&M Engineer	IP	0	2	1	1	1	3													0	5
PDM Supervisor	IP	1	0				0													0	0
PDM Specialist	IP	3	3				0													0	3
BRO Engineer	IP	2	1				0													0	1
Temporary	IP	1	0				0													0	0
Planning Subtotal		**19**	**18**	**1**	**1**	**0**	**2**	**1**	**3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**24**
MAINTENANCE																					
Kahe																					
Kahe Maint Supervisor	IL	2	2				0													0	2
Boiler Working Foreman	IL	1	1				0													0	1
Elec Working Foreman	IL	1	1				0													0	1
Machinist Work Foreman	IL	1	1				0													0	1
Senior Electrician	IL	4	4				0													0	4
Machinist	IL	3	3				0													0	3
Pipefitter Mechanic	IL	4	3				0			2										2	5
Certified Comb Welder	IL	3	3				0			1										1	4
Insulator	IL	0	0	1			1													0	1
Control Technician	IL	6	6				0					2								2	8
Helper	IL	2	2				0													0	2
Mob Crn & Hvy Eq Oper	IL	1	1				0													0	1
Kahe Maint Subtotal		**28**	**27**	**1**	**0**	**0**	**1**	**0**	**0**	**3**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**33**
Maint Admin																					
O&M Maint Superint	IM	1	1				0													0	1
Rotating Equip Spec	IM	0	0				0				1									1	1
Maintenance Clerk	IM	1	1				0													0	1
Maint Admin Subtotal		**2**	**2**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**3**

Hawaiian Electric Company, Inc.
2007 Rate Case - Power Supply Process Area
Filling of Vacancies in 2006 and 2007

Position	RA	2005 Actual	9/06 YTD Actual	2006 Oct	2006 Nov	2006 Dec	2006 TOT	2007 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2007 TOT	YTD 2007
Honolulu																					
Hono Maint Supervisor	IN	1	1				0													0	1
Boiler Working Foreman	IN	1	1				0													0	1
Elec Working Foreman	IN	1	1	-1		1	0													0	1
Machinist Work Foreman	IN	1	1				0													0	1
Senior Electrician	IN	1	1				0													0	1
Machinist	IN	1	1				0													0	1
Pipefitter Mechanic	IN	0	1				0													0	1
Welder	IN	0	0				0				1									1	1
Insulator	IN	0	0				0			1										1	1
Control Technician	IN	2	2				0					1								1	3
Honolulu Maint Subtotal		8	9	-1	0	1	0	0	0	1	1	1	0	0	0	0	0	0	0	3	12
Travel																					
Traveling Maint Superv	IT	4	4				0													0	4
Senior Supv Overhauls	IT	0	1				0													0	1
Boiler Working Foreman	IT	2	2				0													0	2
Elec Working Foreman	IT	2	1	1			1													0	2
Machinist Work Foreman	IT	2	2				0													0	2
Insulator Work Foreman	IT	1	1				0													0	1
Condenser Crew Leader	IT	1	1				0													0	1
Senior Electrician	IT	8	9	1		-1	0			1										1	10
Machinist	IT	9	8				0			1										1	9
Pipefitter Mechanic	IT	5	6				0			1										1	7
Certified Equip Mechanic	IT	1	1				0	1												1	2
Certified Comb Welder	IT	7	8				0			1										1	9
Control Technician	IT	7	7		2		2													0	9
Helper	IT	3	3				0													0	3
Insulator	IT	9	9	-2			-2			3										3	10
Mob Crane & Equip Oper	IT	0	0				0			1										1	1
Condenser Cleaner	IT	6	7	1			1													0	8
Travel Crew Subtotal		67	70	1	2	-1	2	1	0	8	0	0	0	0	0	0	0	0	0	9	81
Waiau																					
Waiau Maint Supervisor	IX	2	2				0													0	2
Boiler Working Foreman	IX	1	1				0													0	1
Elec Working Foreman	IX	1	1				0													0	1
Machinist Work Foreman	IX	1	1				0													0	1
Senior Electrician	IX	2	4				0													0	4
Machinist	IX	3	3				0													0	3
Pipefitter Mechanic	IX	4	4				0			1										1	5
Certified Comb Welder	IX	2	2				0			2										2	4
Insulator	IX	0	0	1			1													0	1
Control Technician	IX	6	6				0					2								2	8
Helper	IX	1	1				0													0	1
Mob Crn & Hvy Eq Oper	IX	1	1				0													0	1
Waiau Maint Subtotal		24	26	1	0	0	1	0	0	3	0	2	0	0	0	0	0	0	0	5	32
Maintenance Subtotal		129	134	2	2	0	4	1	0	15	2	5	0	0	0	0	0	0	0	23	161
TOTAL POWER SUPPLY O&M		299	306	5	3	2	10	2	13	14	2	5	1	0	0	0	0	0	-1	36	352
POWER SUPPLY - VP																					
Vice President	7V	1	1				0													0	1
VP Secretary	7V	1	1				0													0	1
TOTAL POWER SUPPLY - VP		2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
TOTAL PROCESS AREA		394	396	3	5	4	12	5	19	16	2	5	1	0	0	0	0	0	-1	47	455

Count as of 12/31/06 = 408

NOTE: Count by Dept and Process Area different from HECO-1403 Exhibit, Summary of Recorded and Average Number of Employees by by employee count of one. The one count difference is due to the expected vacancy of the PSSD Transm Planning Dir in late Dec 2006 and the hiring of two Kahe Shift Supervisor in late Dec. 2006.

HECO Splicer

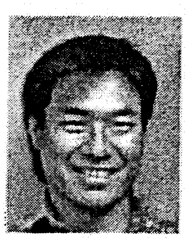
Sent on behalf of Tom Simmons and Dan Giovanni:

The Power Supply Operations & Maintenance Department (PSO&M) is responsible for the safe and reliable operation of our generating units. In recent years the demand for power has increased (and reserve margins have decreased) to the point that we are staffing to operate all our units on a 24/7 basis. The maintenance requirements to sustain reliable operation of these aging units have increased commensurately. At this time, we are pleased to announce the following changes to the **Power Supply Operations and Maintenance (PSO&M) organization, effective June 26, 2006.** These changes will better align the organization with our current needs.

Operations

Station Superintendents will be established for the Kahe and Honolulu/Waiau Power Plants. They will oversee all the work performed on a daily basis and directly supervise the operations personnel at their respective power plants. The Station Superintendents will report to Dan Giovanni, PSO&M Manager.

Jeff Vaughan will be promoted to **Station Superintendent, Kahe Power Plant**. Jeff is currently the Senior Supervisor at the Kahe Power Plant. Jeff joined HECO in 2004 as the Senior Supervisor in O&M Planning. Prior to joining HECO, Jeff worked at AES Hawaii where he was the Vice President, Power Block Superintendent. Jeff holds a Bachelor of Science in Engineering from the Massachusetts Maritime Academy.



Dean Arakawa will transfer as **Station Superintendent, Honolulu & Waiau Power Plants**. Dean is currently the Superintendent, Technical Services Division, in the Power Supply Engineering Department. Dean is a graduate of the University of Hawaii at Manoa with a Bachelor of Science in Electrical Engineering. Dean began his career at HECO in 1990 as a Designer I and has held positions of increasing responsibility in Power Supply Engineering.

Planning & Engineering

The Planning Division will be renamed as the Planning and Engineering Division and dispersed engineering functions within the department will be consolidated into this division.

Karen Mark will transfer as **Superintendent, Planning & Engineering**, reporting to Dan Giovanni. Karen is the current Operations Superintendent and has been with HECO since August 1986. She has held the positions of Senior Supervisor, Project Engineer, Station Engineer and Betterment Engineer. Karen holds a Bachelor of Arts in Economics, Bachelor of Science in Mechanical Engineering and a Masters in Business Administration.

The Planning section of O&M Planning & Engineering will continue to be led by **Senior Supervisor, Planning, Rona Kiyabu.** Rona will supervise the Resource Planners and Planning/Project Coordinators. A graduate of the University of Hawaii at Manoa with a Bachelor of Science in Mechanical Engineering, Rona has over fourteen years of experience with O&M.

John Itai will assume expanded responsibilities as **Senior Supervisor, Engineering and Predictive Maintenance**. The O&M Engineers, Predictive Maintenance Specialists and the Operations Power Engineers will report to John. He has been the Supervisor, Predictive Maintenance since 2001. John has worked for HECO since 1993 when he was hired as a Betterment Engineer.

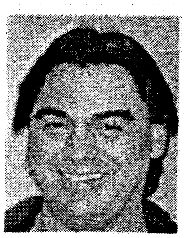
Both Rona and John will report to Karen Mark.

Administration

Lane Hiramoto will become the **Senior Technical Analyst**, reporting to Dan Giovanni. Lane will have diversified responsibilities within the department. He will represent PSO&M interests in initiatives throughout the company as we continue to expand PSO&M generating capability and become involved in more regulatory proceedings. Lane began his twenty year career at HECO as a Betterment Engineer and has held positions of increasing responsibility within Power Supply O&M.

Training

A Training Division will be established in PSO&M to oversee the development and delivery of training for PSO&M employees.



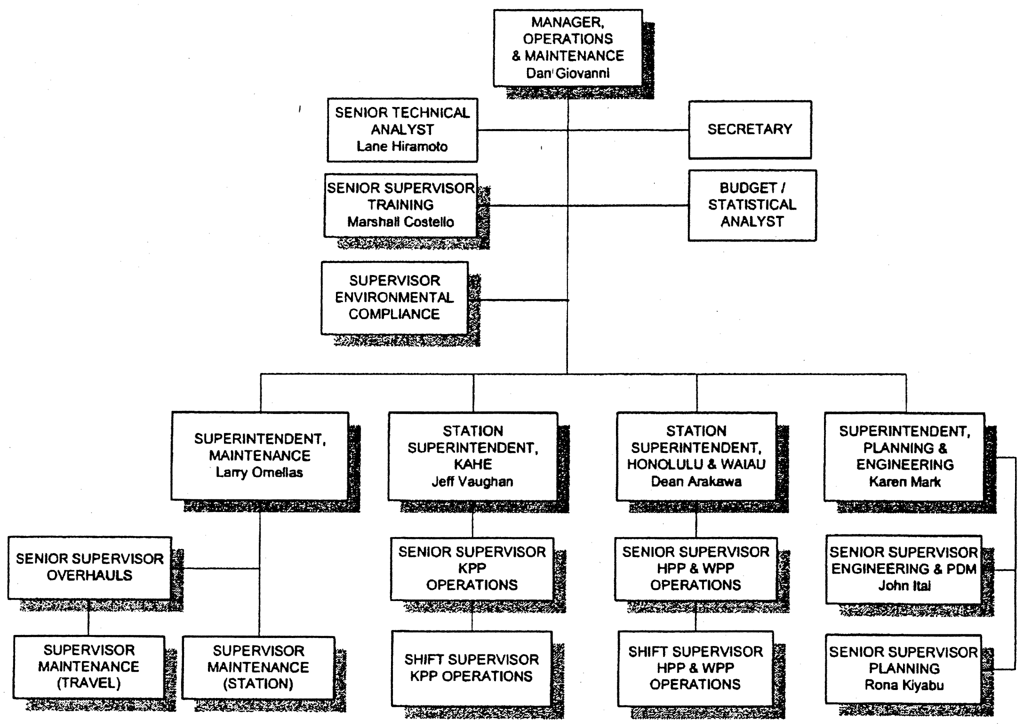
Marshall Costello will transfer into the position of **Senior Supervisor, Training**. Marshall is currently Senior Supervisor, Operations, at Waiau Power Plant. Marshall brings with him the technical knowledge and breadth of experience to lead our multi-disciplined strategy to expand our training efforts and improve the competency of the PSO&M workforce. He will also be called upon to support the troubleshooting needs of O&M and environmental issues at the power plants, facilitate the commissioning of new equipment systems, and coordinate activities with Energy Delivery System Operations. Marshall will report to Dan Giovanni.

Maintenance

To assist with the planning, budgeting, and execution of major maintenance work during scheduled overhauls, a **Senior Supervisor, Overhauls**, will be added to the Maintenance Division to oversee the Travel Maintenance crews. This position will report to Larry Ornellas, Superintendent, Maintenance. The Maintenance Station Supervisors will continue to report to Larry.

The new Power Supply Operations & Maintenance organization appears as follows:

POWER SUPPLY OPERATIONS & MAINTENANCE



We ask you to support these organizational changes and the leaders within, which will bring about a stronger Company as we manage our day to day operations more effectively as we meet the challenges of keeping the lights on with the increased energy demands.

*****Please share or post for those not on e-mail.*****

Hawaiian Electric Company, Inc.
2007 Rate Case

PRODUCTION O&M - OPERATING DIVISION
OVERTIME HOURS

RA	RA Desc	2005		2006		2007
Budget OT						
PIK	Kahe	17,139		15,517		16,062
PIH	Honolulu	4,919		6,831		7,155
PIW	Waiau	23,465		16,824		17,422
Oper Budget		**45,523**		**39,172**		**40,639**
Oth RAs and Categ		55,463		63,271		69,338
Total Budget		100,986	(1)	102,443		109,977
% OT (2)		18%		15%		15%
Actual OT						
PIK	Kahe	17,067		17,412		
PIH	Honolulu	6,426		5,757		
PIW	Waiau	23,427		22,785		
Oper Actual		**46,920**		**45,954**		
Oth RAs and Categ		60,734		66,978		
Total Actual		107,654	(3)	112,932	(4)	
Operation - Excess Overtime						
Actual vs Budget Hrs		**1,397**		**6,782**		
Actual vs Budget % (5)		**3%**		**17%**		

NOTES:

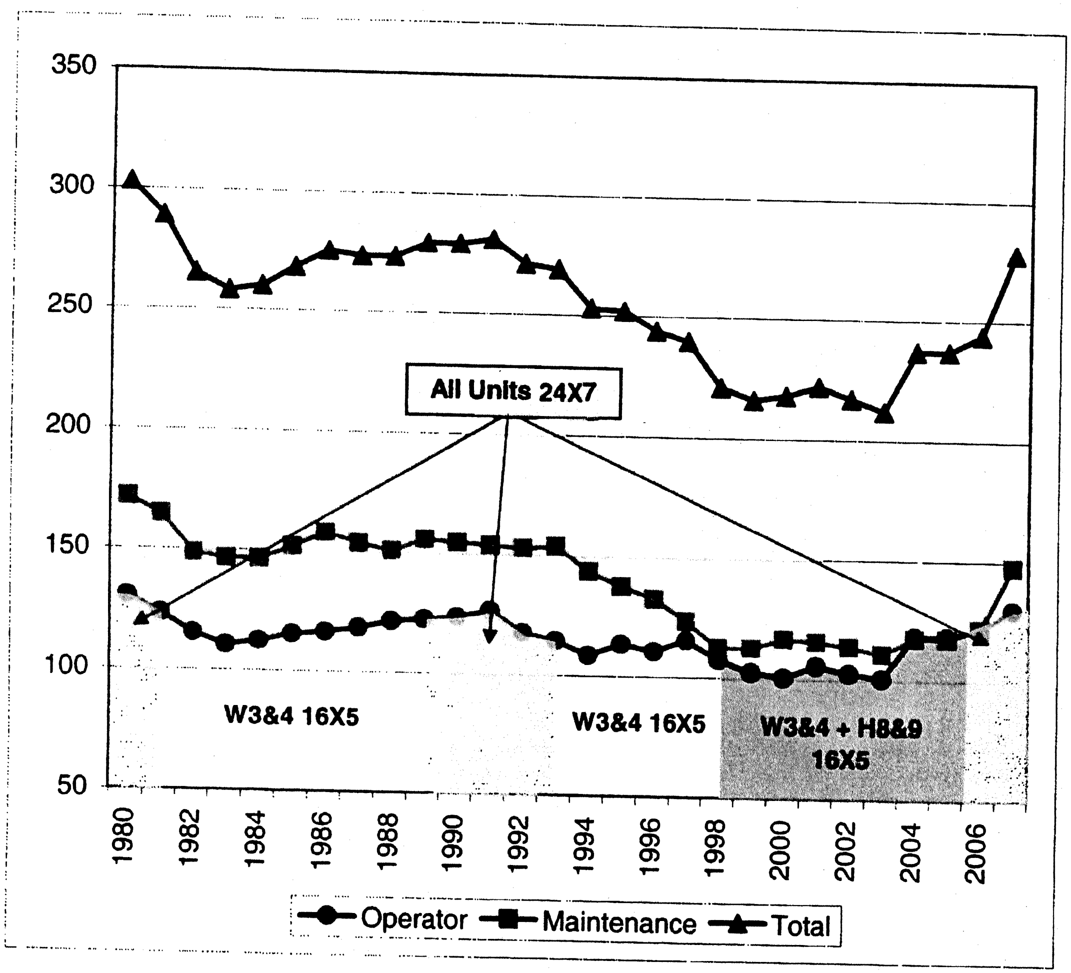
Actual OT hours is as of October 31, 2006.

Above OT is inclusive of all OT work type: Capital, O&M and Clearing.

(1) Agrees with 2005 Rate Case, Docket No. 04-0113, CA-IR-635, page 8 of 8.
(2) "%OT" = (Budgeted OT/Budgeted ST).
(3) Agrees with HECO Payroll Recap Report, 12/28/05, Year End.
(4) Per HECO Payroll Recap Report, 10-31-06, Oct YTD Pay Period and projected average monthly Nov and Dec 2006.
(5) "Actual vs Budget %" = (Actual OT - Budgeted OT)/Budgeted OT.

Hawaiian Electric Company, Inc.
2007 Test Year

O&M DEPARTMENT
TRADES & CRAFTS STAFFING



	T&C Operator	T&C Maintenance	Total
1980	131	172	303
1981	124	165	289
1982	116	149	265
1983	111	147	258
1984	113	147	260
1985	116	152	268
1986	117	158	275
1987	119	154	273
1988	122	151	273
1989	123	156	279
1990	124	155	279
1991	127	154	281
1992	118	153	271
1993	115	154	269
1994	109	144	253
1995	114	138	252
1996	111	133	244
1997	116	124	240
1998	108	113	221
1999	103	113	216
2000	101	117	218
2001	106	116	222
2002	103	114	217
2003	101	111	212
2004	119	118	237
2005	119	118	237
2006	122	122	244
2007	130	148	278

Hawaiian Electric Company, Inc.
2005 TEST YEAR

OTHER PRODUCTION MAINTENANCE NON-LABOR EXPENSE
2003 ACTUAL VS. 2005 TEST YEAR
($ Thousands)

		(A)	(B)	(C)	(D)
	EXPENSE	2003 ACTUAL	2005 TEST YEAR	CHANGE	%
1	Material	$ 6,849	$ 6,427	$ (422)	(6)
2	Outside Srvcs	$ 7,538	$ 10,365	$ 2,827	38
3	Transportation	$ 215	$ 110	$ (105)	(49)
4	Labor Related On-Cost (A)	$ 924	$ 1,729	$ 805	87
5	Adj & Normalization	$ -	$ 161	$ 161	#DIV/0!
6	TOTAL	$ 15,526	$ 18,792	$ 3,266	21

(A) - Labor Related On-Cost include Energy Delivery On-Cost, Power Supply On-Cost, Corporate Admin On-Cost, Employee Benefit On-Cost and Payroll Taxes On-Cost.

Hawaiian Electric Company, Inc.
2007 Rate Case

Production O&M - Maintenance Division
Outside Services (Incl Others)

(In Thousands)

		2005		2006		2007
Budget						
PIL	Kahe	$1,211		$2,629		$5,361
PIN	Honolulu	$905		$912		$1,438
PIX	Waiau	$1,985		$1,996		$2,187
PIT	Travel	$4,879		$3,746		$3,327
Maint Budget		**$8,980**		**$9,283**		**$12,313**
Oth RAs and Categ		$1,385		$584		$1,509
Total Budget		$10,365	(1)	$9,867		$13,822
Actual						
PIL	Kahe	$3,502		$2,417		
PIN	Honolulu	$880		$1,092		
PIX	Waiau	$3,297		$3,424		
PIT	Travel	$6,116		$5,839		
Maint Actual		**$13,795**		**$12,772**		
Oth RAs and Categ		($1,353)	(2)	$2,420		
Total Actual		$12,442		$15,192	(3)	
Maint -						
Diff- Actual vs Budget		**$4,815**		**$3,489**		
% - Actual vs Budget		**54%**		**38%**		

NOTES:

Actuals are as of October 31, 2005

(1) Ref 2005 Rate Case, Docket No. 04-0113, Exhibit HECO -626
(2) Credits for PIT273W09NEP0000937900 ($1,615,896) and PIX262W08NENPIZZZZZ900 ($539,248) are compiled in "Oth RAs and Categ" in this exhibit.
(3) Includes Projected months after 10-31-06.

Hawaiian Electric Company, Inc.
2007 Rate Case

Production O&M - Maintenance Division
Overtime Hours

RA	RA Desc	2005		2006		2007
Budget OT						
PIL	Kahe	7,294		7,926		9,110
PIN	Honolulu	1,632		1,630		3,685
PIX	Waiau	7,099		6,948		10,206
PIT	Travel	30,875		42,650		39,920
Maint Budget		**46,900**		**59,154**		**62,975**
Oth RAs and Categ		54,086		43,289		47,002
Total Budget		100,986	(1)	102,443		109,977
% OT (2)		17%		21%		22%
Actual OT						
PIL	Kahe	12,938		12,528		
PIN	Honolulu	1,346		1,311		
PIX	Waiau	14,782		16,203		
PIT	Travel	31,633		36,934		
Maint Actual		**60,699**		**66,976**		
Oth RAs and Categ		46,955		45,956		
Total Actual		107,654	(3)	112,932	(4)	

Maintenance - Excess Overtime

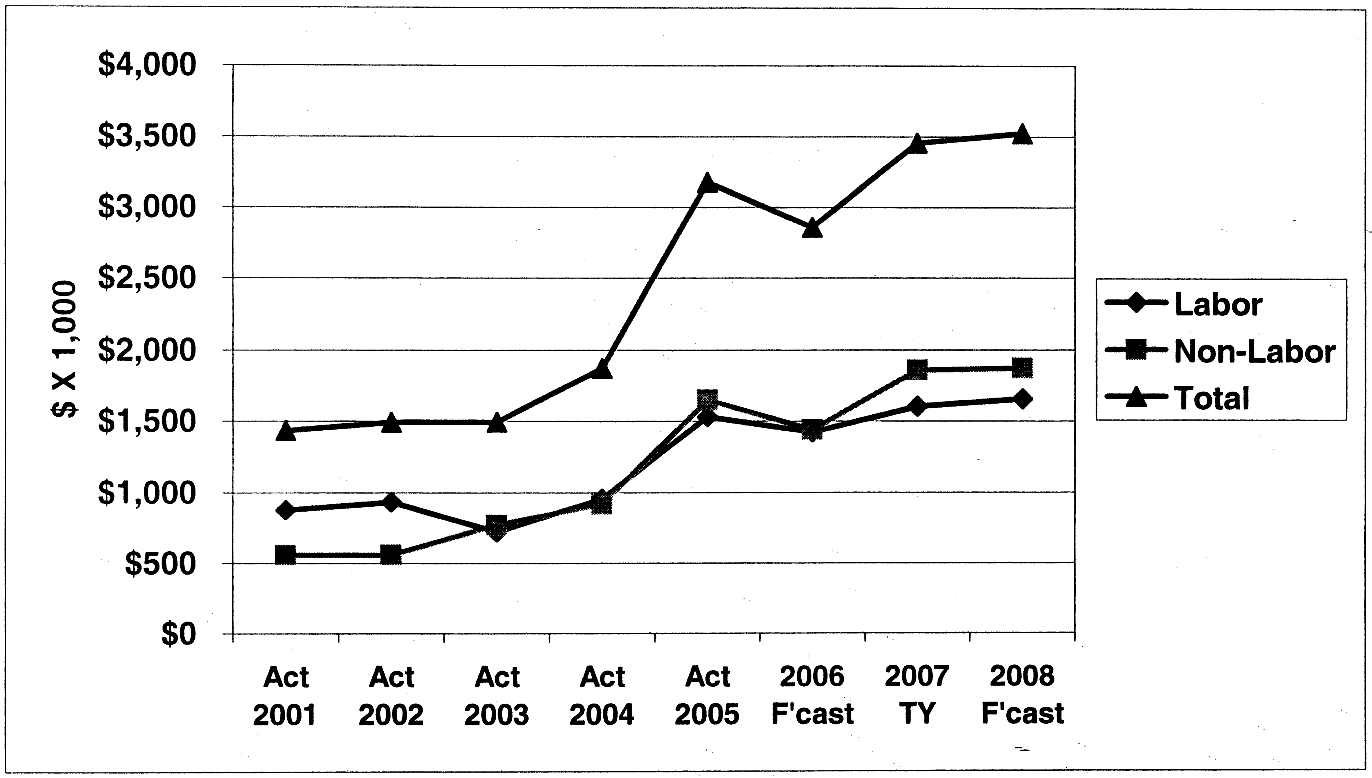
	2005	2006
Actual vs Budget Hrs	**13,799**	**7,822**
Actual vs Budget % (5)	**29%**	**13%**

(1) Agrees with 2005 Rate Case, Docket No. 04-0113, CA-IR-635, page 8 of 8.
(2) "%OT" = (Budgeted OT/Budgeted ST).
(3) Agrees with HECO Payroll Recap Report, 12/28/05, Year End.
(4) Per HECO Payroll Recap Report, 10-31-06, Oct YTD Pay Period and projected average monthly Nov and Dec 2006.
(5) "Actual vs Budget %" = (Actual OT - Budgeted OT)/Budgeted OT.

Hawaiian Electric Company, Inc.
2007 Test Year

Training Cost (O&M Direct and Clearing Costs)
(In Thousands) - ABM Activities 785-797

	Act 2001	Act 2002	Act 2003	Act 2004	Act 2005	2006 F'cast	2007 TY	2008 F'cast
Labor	$875	$931	$722	$955	$1,528	$1,420	$1,600	$1,653
Non-Labor	$556	$558	$771	$916	$1,647	$1,439	$1,856	$1,870
Total	$1,431	$1,489	$1,493	$1,871	$3,175	$2,859	$3,456	$3,523



HECO-621
DOCKET NO. 2006-0386
PAGE 1 OF 1

Hawaiian Electric Company, Inc.
2007 Test Year

OTHER PRODUCTION OPERATIONS EXPENSE
($ Thousands)

Line		RECORDED					2006 BUDGET	2007 TY ESTIMATE	2005 vs 2007	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2001	2002	2003	2004	2005	2006	2007	$	%
1	Labor	$10,766	$11,140	$11,278	$11,742	$12,304	$13,957	$14,242	$1,938	16%
2	Non-Labor	$9,385	$8,274	$8,895	$8,544	$10,154	$12,998	$14,870	$4,716	46%
3	TOTAL	$20,151	$19,414	$20,173	$20,286	$22,458	$26,955	$29,112	$6,654	30%
	Percentage Change		-4%	4%	1%	11%	20%	8%		

Source: Columns A to F: HECO-WP-101, S1 Report, page 2
Column G: Agrees with HECO-602, Column (D)

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2007 Test Year

OTHER PRODUCTION MAINTENANCE EXPENSE
($ Thousands)

Line		RECORDED					2006 BUDGET	2007 TY ESTIMATE	2005 vs 2007	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H=G-E)	(I=H/E)
		2001	2002	2003	2004	2005	2006	2007	$	%
1	Labor	$8,329	$8,867	$9,353	$9,329	$10,519	$12,902	$15,219	$4,700	45%
2	Non-Labor	$14,192	$16,013	$15,526	$20,841	$24,151	$21,354	$23,891	-$260	-1%
3	TOTAL	$22,521	$24,880	$24,879	$30,170	$34,671	$34,256	$39,110	$4,439	13%
	Percentage Change		10%	0%	21%	15%	-1%	14%		

Source: Columns A to F: HECO-WP-101, S1 Report, page 2.
Column G: Agrees with HECO-602, Column (D)

Note: Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION O&M EXPENSE BUDGET ADJUSTMENTS
($ Thousands)

Line	Adjustments	(A) Operations Non-Labor	(B) Maintenance Non-labor	(C) Total
1	Distributed Generation	-155	0	-155
2	Abandoned Projects	42	0	42
3	Performance Incentive Compensation	-279	0	-279
4	TOTAL	-392	0	-392

Source:
Col (A), Agrees with HECO-602, Column (B)
Col (A), Line 2: HECO-1019.
Col (A), Line 3: HECO-1004.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION O&M EXPENSE NORMALIZATIONS
($ Thousands)

Line		(A)	(B)	(C)
	Normalization	Operations Non-Labor	Maintenance Non-labor	Total
1	Emissions Fees	-252	0	-252
2	Smart Signal	0	-598	-598
3	IRP	31	0	31
4	TOTAL	-221	-598	-819

Source:

Col (A), Line 1:	HECO T-6, ($1090 - (10/13) X $1090 = $252)
Col (B), Line 2:	HECO T-6, ($897/3 = $299; Adjust OUT 2 years or 2 X $299 = $598)
Col (A), Line 3:	HECO T-9 (Mr. Alan Hee)

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION OPERATION NON-LABOR EXPENSE
2005 ACTUAL VS. 2007 TEST YEAR
($ Thousands)

		(A)	(B)	(C)	(D)
	EXPENSE	2005 ACTUAL	2007 TY ESTIMATE	CHANGE	%
1	Material	$ 2,163	$ 2,062	$ (101)	(5)
2	Transportation	$ 101	$ 135	$ 34	34
3	On-Cost	$ 2,491	$ 2,322	$ (169)	(7)
4	Outside Srvcs/Other	$ 5,399	$ 10,964	$ 5,565	103
5	SUBTOTAL	$ 10,154	$ 15,483	$ 5,329	52
6	Adj & Normalizations	$ -	$ (613)	$ (613)	
7	TOTAL	$ 10,154	$ 14,870	$ 4,716	46

Line 3 - Labor Related On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Line 7 TOTAL: Agrees with HECO-622

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION OPERATION NON-LABOR EXPENSE
DISTRIBUTED GENERATION & DISPATCHABLE STANDBY GENERATOR EXPENSE
($ Thousands)

		(A)	(B)	(C)	(D)
	EXPENSE	2005 ACTUAL	2007 TY ESTIMATE	CHANGE	%
1	Labor	$ 62	$ 106	$ 44	71
2	Material	$ 1	$ 22	$ 21	2100
3	Outside Srvcs/Other	$ 52	$ 442	$ 390	750
4	Other (Rental)	$ 188	$ 2,971	$ 2,783	1480
5	On-Cost	$ 38	$ 76	$ 38	100
6	Transportation	$ -	$ 3	$ 3	100
7	Adj & Normalizations	$ -	$ (155)	$ (155)	100
8	TOTAL	$ 341	$ 3,465	$ 3,124	916

Line 5 - Labor Related On-Cost include Energy Delivery On-Cost and Power Supply On-Cost.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION O&M EXPENSE
DSG REGULATORY ASSET AMORTIZATION
($ Thousands)

DSG Regulatory Asset 675

Year	Annual Amortization	Unamortized at YearEnd	Average Unamortized
2007 TY	30	645	660
2008	71	574	610
2009	72	502	538
2010	72	430	466
2011	72	358	394
2012	71	287	323
2013	72	215	251
2014	72	143	179
2015	72	71	107
2016	71	0	36

Source: DSG Regulatory Asset of $675,000 from HECO-1704.

Research and Development 2007 Test Year Estimate

The Company's 2007 test year estimate for research and development ("R&D") expenses for renewable energy that are included in Production Operation & Maintenance is $1,181,000 for activities primarily conducted by Technology Division and Senior Vice-President Energy Solution & Technology. In general, the estimate includes expenses associated with near-term locally-based research and development activities to further HECO's evaluation and implementation of new technologies related to electric utility operations, renewable energy, alternate energy, and emerging technologies and primarily labor related to Technology Division activities. The Technology Division and Senior Vice President Energy Solutions budgets are covered in two testimonies—HECO T-6 Production Operations and Maintenance (R&D) and HECO T-13 Corporate and Property Accounting (Electric Power Research Institute membership and other related activities). Specifically, the major R&D activities include:

1)	local EPRI matching funds	$249,000
2)	recurring renewable energy funds	$65,000
3)	renewable energy initiative	$300,000
4)	biofuels initiatives	$100,000
5)	electronic shock absorber	$221,000
6)	Sun Power for Schools	$40,000
7)	Labor	$104,000
8)	Overheads	$76,000
9)	other activities	$25,000
	TOTAL	$1,181,000*

(*figures may not total exactly due to rounding)

The 2007 test year amount was determined based on costs incurred in prior years for near-term research and development, studies, evaluation and implementation of new technologies related to electric utility operations, renewable energy, alternate energy, and emerging technology projects. Also included were funds used to leverage estimated 2007 EPRI Tailored Collaboration funding and HECO labor and overheads.

HECO's local research and development costs are budgeted to further HECO's near-term research and development, studies, evaluation and implementation of renewable energy, alternate energy, and emerging technologies. The intent of the local research and development funding is to fund projects and studies that are directly related to HECO issues that may not be addressed under the general EPRI membership research package.

These expenses are used to cover general research and development activities related to renewable energy and alternate energy organization memberships, publications and reports, travel to renewable energy and alternate energy conferences, seminars and training, and initiatives in wind, biomass and other renewable energy, alternative energy and emerging technologies (such as hydrogen and fuel cells).

The research activities will concentrate on areas where the project results will have impact and bearing on the technology or project that could be implemented by HECO in the near-term. These activities would include, but are not limited to, technology research, development and demonstration, feasibilities studies, resource data collection, land availability studies, collecting information on technology performance, cost, emission, etc. and other activities. While wind initiatives were identified in the budget, HECO maintains that flexibility will be needed as other renewable resources may also need funding (that was not foreseen when developing its budget).

This budgeted amount reflects increased activities in the renewable energy and alternate energy areas. The Governor, state energy office, state legislature, and Public Utilities Commission have a strong interest in increasing renewable energy development in Hawaii. HECO is required to meet a state law mandating that a certain percentage of its electric sales be derived from renewable energy (i.e., the Renewable Portfolio Standards law). The new initiatives are related to wind, biomass and other renewable energy, alternate energy and emerging technologies (such as hydrogen and fuel cells). The increased activities are a direct reflection of HECO's strong commitment to increase its operational efficiency, offer new energy solutions, and increase its renewable energy portfolio.

HECO and its customers benefit from the local research and development activities. Local research and development funds can be directed to areas having direct impact in Hawaii. For example, there is strong interest for the state to increase renewable energy development in Hawaii. Renewable portfolio standards laws are in place and the 2005 Legislative session recently amended this law for renewable energy development in Hawaii. Local research and development funds are used to leverage local research and development monies with EPRI funds to conduct research, development and demonstration projects and studies related to HECO specific projects.

It important to have local research and development projects and activities. While EPRI membership has assisted HECO in gaining general utility information, it is the local research and development funds that can be directed to specific areas of interest in Hawaii since these interests may not be adequately represented by the mainland utility membership.

<u>Local EPRI matching funds</u>

A sum of $249,000 is used as a placeholder to match EPRI membership funds, Tailored Collaboration ("TC") for local research and development projects. In the past, the matching funds have been located in the O&M budget of the HECO department that will have an EPRI TC project. HECO Accounting requested that this cost share be located in the Technology Division budget starting in 2005.

The local EPRI matching funds used to match EPRI TC funding have not always remained at the same level over time. As shown below, the actual local EPRI matching funds have varied for HECO:

- 2000: $452,049
- 2001: $225,720
- 2002: $155,000
- 2003: $303,479
- 2004: $243,300
- 2005: $152,500

The amount of local EPRI matching funds is a function of the TC funds available to HECO, which depend on the EPRI programs and projects that HECO subscribes to as part of its membership. Only some of the EPRI products offerings have TC funds associated with them. When HECO subscribes to EPRI products each year, some products will have TC funds available for HECO matching.

The types of R&D projects that will be funded by the local EPRI matching funds in 2007 are as follows (note the type of R&D projects vary each year depending on the company needs):

Project Title	Project Description	Local EPRI match Funds
Underground Cable Replacement Policy Model Development	Review and utilize HECO's cable data to develop an optimal Repair/Replace policy for HECO's UG direct buried cables. Train company personnel to use the model for future projects.	$27,500
Fargo ACSR Compression Dead-End Connector Failure Investigation	HECO has experienced four failures of Fargo ACSR Compression Dead-End connectors on the Waiau-Ewa Nui 138kV circuits. EPRI to inspect the failed components and the documentation related to the failures and develop and implant any component testing needed to identify the cause of these failures.	$48,397
Underground Best Practices Assessment	Review and assess HECO's underground installation and maintenance practices and compare them to industry best practices.	$30,000
T&D Inspector Training	EPRI has started an on-line training program with photo's and descriptions of a limited amount of components on a typical electrical distribution and transmission system. There is also a test that is associated with the on-line training to measure the knowledge gained from the training. EPRI has talked about expanding the on-line training to more components and C&M would like to work with EPRI in continuing the development of this training to	$35,000

	increase the number of components to be trained on.	
Thermal and Compressed Air Storage UPS	Demonstrate the thermal and compressed air storage uninterruptible power supply system. This is a battery-less extended ride through technology. As an alternative to battery-based UPS solutions. The unit could provide 15 minutes of ride through at a demand of 80kW for hospitals, manufacturing processes and data centers with critical loads of 80kW (or less) and a required ride through duration of 15 minutes (or less).	$47,500
Beyond Sun Power: An Enterprise Approach to Energy and Learning Solutions	Evaluate the effectiveness of direct current (DC) fluorescent electronic ballasts designed to fit in standard linear fluorescent lighting fixtures housing one or two T8 fluorescent lamps in a classroom situation.	$31,434
Demand Control Ventilation Demonstration	The energy savings potential of demand control ventilation (DCV) in air conditioning systems in Hawaii will be determined, and the accuracy of building energy simulation programs in predicting the energy savings of DCV will be verified.	$29,200
TOTAL		$249,031

Note: Other EPRI funds may be used in some of these projects. The total project amount could vary pending any change of work scope. There are existing EPRI biofuels and wind integration studies on –going. HECO has obtained direct benefits by using local EPRI matching funds with EPRI TC funds. Some of the projects that received this type of funding include optimization of power plant maintenance techniques, implementation of predictive maintenance tools and procedures, equipment evaluation and techniques to enhance the transmission and delivery of electrical energy, and development of methodologies and systems to assess the impact of intermittent generation technologies on the utility grid.

Recurring renewable energy funds

The 2007 test year estimate includes the following for recurring renewable energy seed monies:

- $50,000 recurring renewable research and development--seed monies for general renewable energy, new technologies, studies, assessment, etc.
- $15,000 for recurring renewable energy memberships, travel and publications;

Renewable energy initiative

The 2007 test year estimate also includes an amount of $300,000 to be used for renewable energy initiatives. There is a State law for electric utilities to increase the percentage of renewable energy on its electric system. Wind technology is one renewable technology that is mature. HECO recently participated with Department of Business, Economic Development & Tourism and National Renewable Energy Laboratory to develop high resolution wind maps which identified potential areas wind development for the islands. Pumped storage hydroelectric is another mature renewable energy resource that could be used in the HECO system. The funds identified would be used to initiate tasks that help increase the development of this and other technologies: advanced technology assessments, siting work, data collection for resource verification and confirmation, investigation of operational and other issues, land use, permits and approvals, etc.

The renewable energy initiative monies been used in the past. In 2005 and 2006, a subcontract was signed for greenfield pumped storage hydroelectric feasibility studies on the Big Island and Maui. Expenditures for this study are provided below:

Year	HECO Renewable Initiative Monies
2005	$15,175
2006*	$202,425
Total	$217,600

* Actual and projected

The general objectives for pumped storage hydroelectric feasibility studies on the Big Island and Maui were to:

- Establish proposed concepts for evaluation,
- Develop sufficient information for establishing project operating characteristics, and
- Develop preliminary cost estimate

The study has been completed. In general, the study provided a preliminary design of reservoirs, penstock, and pump/turbines and layout of a 50 MW pumped storage facility that can operate in hydroelectric mode for about 12 hours. As the next steps, and to better understand the operational characteristics of a pumped storage hydro system, HECO, HELCO and MECO have funded a study to examine ancillary system benefits. The study is currently on-going. The total project cost is about $50,000 (HECO's share is $20,000 and HELCO and MECO's share is $15,000 each). The follow-up of this work is discussed in HECO T-13 testimony related to Electrical System Analysis Study on Maui.

The 2007 funds are expected to be used for the assessment and evaluation of a wind farm development at a Kahuku military site. HECO has been in communications with the Army to develop a wind farm in the Kahuku training area. Based on ongoing discussions with the Army, the site may be leased by HECO and HECO would then competitively bid for a wind project developer.

HECO has submitted to the Army a proposed wind monitoring program to allow HECO subcontractors to install, monitor, and evaluate the wind speed and direction at multiple sites for a minimum one-year period. HECO is awaiting Army Corps and Department of Fish & Wildlife review and approval of this program. HECO is also awaiting approval of a Conservation District Use Permit by the State of Hawaii Department of Land and Natural Resources. The 2007 funds will be used to fund the stationary meteorological tower and sensors and mobile acoustical trailer and installation, monitoring, evaluation and reporting of this effort. HECO requires flexibility in prioritizing and expending funds for these initiatives to maximize the efficacy of its renewable energy strategy for meeting the requirements of Hawaii's Renewable Portfolio Standards law.

The budget for the subcontractors involved in the Kahuku military wind farm development and the applicable fees are as follows:

Subcontractor	General Work Scope	Budget*
AWS Truewind	Procure, install, monitor, evaluate (met tower and sodar data), update wind mapping and report findings	$138,050
Eagle Construction	Install, maintain and remove met tower	$86,600
Barry Neal and Associates	Install, maintain and remove sodar trailer	$50,000
Planning Solutions	Review and assist in permitting and approval requirements, conduct archaeological review and report	$46,094
Pacific Consulting Services, Inc.	Conduct wind farm photo simulations	$18,000
Application fees	US Army Corp of Engineers, DLNR	$9,500
Lease fee	Met tower sensor on existing Global Signal communication tower lease	$22,000
TOTAL		$370,244

* Note: Budgets are subject to change based on adjustments to project work scopes (i.e., an avian radar survey will be needed per Fish & Wildlife discussion, estimated to cost at least ~$40,000 and is not included in any of the above budgets at this time). Some work has occurred in 2006, but the majority of work will be completed in 2007 once HECO receives necessary permits and permission to enter the property. Some charges will be made in 2008 upon completion of work tasks.

The general milestones for the Kahuku military wind farm project are:

- Obtain Army approval for wind monitoring
- Obtain federal and state permits and approvals
- Install and monitor wind sensors for at least one year
- Obtain Army lease for potential wind farm
- Issue wind Request for Proposal to wind developers
- Select wind developer
- Obtain power purchase agreement with wind developer
- Obtain PUC approval
- Achieve commercial operation.

Biofuels Initiatives

The 2007 estimate includes an amount of $100,000 that will be used for initiatives related to biomass energy or biofuels.

There is definite interest in biofuels use in Hawaii. About 31% of Hawaii's imported oil is used for electrical generation and the rest, about 69%, is used in other energy sectors including transportation. The majority, about 61%, is used in the transportation sector (ground, air and marine). Moreover, the vast majority of the fuel oil that HECO uses to generate electricity is the residual from the refining process to produce the jet fuel and gasoline for the transportation sector. While the State's focus in recent years has been almost exclusively on alternatives to fossil fuels for electrical generation, Hawaii will not make any significant reductions in its imports of petroleum for Hawaii's energy needs unless it addresses the transportation sector. Biofuels can help to reduce our imported oil use in Hawaii in the ground transportation sector.

The primary liquid biofuels being discussed or used in Hawaii are ethanol (converted from corn or molasses or other sugar feedstocks) and biodiesel (recovered from used cooking oils or converted from biomass crops such as soybeans). HECO has been using biodiesel fuels (B20) in its diesel truck fleet (about 110 vehicles) for several years. MECO and HELCO are also using biodiesel fuels (B20) in its diesel fleets (46 and 67, respectively). MECO is using biodiesel fuel (B100) as a startup/shutdown fuel for some of its diesel generators on Maui (about 1,000 gallons per month). MECO is developing a test plan and is planning to seek Department of Health approval to test the use of neat biodiesel (B100) for normal use on the diesel generator that is using the fuel as a startup and shutdown fuel. MECO will also examine B100 use on its other diesel generators and combustion turbines.

However, electric utility experience with biofuels for power generation is limited. Methanol fuel was used in a combustion turbine demonstration for a short period of time many years ago. Although small-scale testing on combustion turbines fired with ethanol has been conducted, ethanol is not being used in stationary power generating units on a commercial basis. There is a need to increase the biofuels experience base in the electrical generation sector. Recently, New York Power Authority has tested biodiesel blends (up to B20) in their steam boiler power plant and the Tennessee Valley Authority tested biodiesel (B100) in a diesel generator.

HECO is interested in biofuels for a number of reasons:

- Biofuels (e.g., biodiesel and ethanol) represent a potential firm renewable energy option that could be used in new and existing electrical generating facilities.
- Biofuels can reduce utility's imported oil consumption.
- Biofuels can be counted towards renewable portfolio standard ("RPS").
- Biofuels may offer environmental benefits.

HECO has an active multi-year, multi-phase research and development program to examine biofuels for stationary power generation consisting of the following:

- Phase 1 – Biofuels resource assessment
- Phase 2 –Combustion testing
- Phase 3 – Generating unit assessment and infrastructure and operational assessment
- Phase 4 – Utility-scale demonstration

Phase 1 and Phase 2 have been completed.

The Phase 1 study was completed by a UH researcher (Dr. Charles Kinoshita) in 2004. The tasks included resource screening and assessment; identifying the most promising biofuels and blends; assessing the supply potential, availability, and pricing; and analyzing and provide specifications of biofuels and blends. The blends investigated were: neat ethanol and 7.7% ethanol in diesel ("E-Diesel"); neat biodiesel (from waste grease) and 20% biodiesel in diesel ("B20").

The key results from the Phase 1 study were:

- Biodiesel and ethanol are the most promising candidate liquid biofuels in Hawaii based on potential reliability of supplies, compatibility with existing and planned units, and cost.
- Supplies are limited.
- Ethanol. No ethanol is produced in Hawaii yet. The potential ethanol from sugars is approximately 40 million gallons per year.
- Biodiesel. supply is limited – about 450,000 gallons of biodiesel is collected from waste grease currently produced in Hawaii. The potential biodiesel from waste grease is approximately 3 million gallons per year.
- Regarding the status of the Phase 2 tasks, the testing has been completed by Southwest Research Institute ("SwRI") using EPRI funds. The tasks included combustion performance testing; emissions testing (carbon monoxide, carbon dioxide, oxides of nitrogen, sulfur dioxides, particulate matter and hydrocarbons); and seeking qualitative results (trends) relevant to utility combustion turbine at two test points (idle and high power) in triplicate runs using three blend levels for ethanol and biodiesel (5%, 7.7%,

and 15% ethanol in diesel by volume and 5%, 10%, and 15% biodiesel in diesel by volume).

The combustor testing was completed SwRI in 2005. The key results were:

- Ethanol blends compared to base diesel fuel:
  At high power condition:
  - Hydrocarbons, carbon monoxide ("CO"), oxides of nitrogen ("NOx"), and combustion efficiency are neutral
  - Sulfur dioxide ("SO2"), particulates, and polycyclic aromatic hydrocarbons ("PAHs") are reduced

  At idle condition:
  - Hydrocarbons, CO, and PAH are increased

- Biodiesel blends compared to base diesel fuel:
  At high power condition:
  - Hydrocarbons, CO, NOx, and combustion efficiency are neutral
  - SO2, particulates, and PAHs are reduced

  At idle condition:
  - Hydrocarbons, CO, NOx, and particulates are neutral
  - SO2 and particulates are reduced

- Emissions penalties may be due to surfactant used in ethanol blends

- Emissions penalties at idle may be avoided by using pure diesel at startup

In 2005 and 2006, SwRI was subcontracted to conduct qualitative combustor performance efficiency and emission evaluation in Phase 2 of HECO's biofuels program. Biomass initiative funds were leveraged with EPRI funds (about 60% of the total project funding was from biomass initiative funds).

Year	Expenditures
2005	$132,025
2006	$22,769
Total	$154,794

Regarding the status of Phase 3, HECO has contracted with Black & Veatch ("B&V") using EPRI funds for the following activities:

1. Conduct an inquiry to manufacturers of the steam boilers, diesel generators, and combustion turbines that are part of the HECO, HELCO and MECO systems. The purpose of this project is to obtain feedback from these manufacturers on the impacts biofuels may have on the performance, emissions, operation, and maintenance related

to these units.

2. Investigate operational and implementation issues faced by utilities in using biofuels (e.g., delivery, storage, operations, maintenance, environmental, policy) for a particular HECO generating facility.

(Execution of Activity #2 will be made at a later date pending the results of Activity #1).

Depending on the test requirements for MECO's planned biodiesel tests and the results and recommendations of the Phase 3 study, HECO will use the 2007 test year biomass initiatives funds to conduct follow-up activities or studies as needed. HECO will leverage EPRI and other funding sources in these activities. HECO requires flexibility in prioritizing and expending funds for these initiatives to maximize the efficacy of its renewable energy strategy for meeting the requirements of Hawaii's Renewable Portfolio Standards law.

HECO is involved in biofuels activities in addition to the R&D activities described above. On April 7, 2006, HECO issued a solicitation of interest ("SOI") to ethanol suppliers to explore the possibilities of entering into a multi-year arrangement to supply ethanol for potential use at the planned Campbell Industrial Park Generating Station and possibly in other generating units. The SOI asked prospective suppliers to indicate their ability to provide ethanol to specifications such as chemical composition and heat generating capability for use in a blend of ethanol and naphtha by the Campbell Industrial Park Generating Station. This announcement is viewed as a positive signal to ethanol suppliers in creating a market for locally-produced ethanol, and thus supporting the local agriculture industry. In addition, at the recent evidentiary hearings (Docket No. 05-0145) for the Campbell Industrial Park Generating Station and Transmission Additions, HECO stated its willingness to commit to using 100% biofuels in its proposed combustion turbine unit in accordance with the terms of a Stipulation entered into by the Consumer Advocate and HECO, and filed with the Commission, on December 4, 2006. To reach this goal, HECO will take steps to design to accommodate biofuels, establish a biofuel supply, modify the air permit to allow use of the chosen biofuels and take aggressive steps to implement the process. HECO engineers and combustion turbine manufacturer have been in discussions on the use of biofuels on this unit.

<u>Electronic shock absorber</u>

The Electronic Shock Absorber ("ESA") demonstration was installed in late 2005 at the Lalamilo wind farm substation. The ESA is the first-of-a-kind demonstration unit developed from idea, patent approval, to design, procurement and construction of a demonstration unit dealing with wind integration issues. While commercial products for the main components were used, the integration devices of these commercial productions and associated software are first-of-a kind.

The purpose of the ESA is to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the wind farm caused by the variable nature of wind. HECO, HELCO, and MECO have teamed with a private company to conduct a study and confirm that a device can be developed from commercial products for installation between a wind farm and the utility grid.

With the increasing penetration of wind power on electric grids, the short term power fluctuations from the wind farms have been causing, and are continuing to cause significant problems in voltage stability and frequency swings and ultimately the overall stability of the grid. In addition, wind-farm susceptibility to faults on the utility system can very quickly result in all of the wind generation tripping off the system.

In many utility situations, it is also necessary that the point of interconnection ("POI") with the utility power system have a means to allow voltage regulation as the wind farm and utility system conditions change. As part of this ESA system program, the two needs/requirements or functions to be performed include voltage regulation at the POI and power fluctuation smoothing.

The ESA is project has been divided into two phases.

- phase 1—2003: a detailed analysis of the wind-farm energy device was completed. Phase I included alternative ESA designs and approximate capital and O&M costs for these alternative systems.

- phase 2—2004 to 2006: an ESA demonstration unit was designed, built and tested on a modular test bed.

The phase 2 ESA demonstration schedule was as follows:

2004 work effort included:

- development of project specification
- supply of single-line diagram
- development of product design
- procurement and evaluation of ultracapacitors
- initial report on system modeling
- Procurement and initial testing of inverter

2005 work effort included:

- procurement and assembly of prototype enclosure
- development of basic controls platform and basic control hardware
- shipment from factory
- installation

2006 work effort includes:

- shakedown and testing
- development of final report

The actual expenses for 2004, 2005 and 2006 phase 2 ESA demonstration expenses are set forth in following table:

Year	HECO Cost Share	HELCO Cost Share	MECO Cost Share	Total
2004	$151,450.00	$75,725.00	$75,725.00	$302,900.00
2005	$264,528.25	$66,959.07	$91,959.07	$423,446.39
2006	$30,290.00	$15,145.00	$15,145.00	$60,580.00
Total	$446,268.25	$157,829.07	$182,829.07	$786,926.39

After the shakedown period, the ESA demonstration unit operated and performed successfully as designed in smoothing the wind farm signal to the electrical grid. Unfortunately, however, the ESA demonstration unit was damaged by the October 15, 2006 earthquake that originated off the western coast of the Big Island. A team is inspecting and assessing the damage to the ESA unit. The future of the ESA demonstration unit will depend on the findings of this and other assessments (if needed). After all information is gathered and assessments made, a decision will be made to either salvage the main components of the ESA, build a new unit, or examine other options.

The 2007 estimate includes $221,000 for the ESA. The ESA funds for 2007 are expected to be used to carry out any future assessment and action plans resulting from the assessment.

It important to have an ESA because, as more wind farms are being installed and proposed in the islands, the ESA is expected to help address the short term fluctuations from the wind farm. The success of the ESA may help increase the number of wind farms in the islands.

Sun Power for Schools

Sun Power for Schools, a program that started in 1996, is a partnership between HECO, HELCO, MECO, the State Department of Education, schools, and our customers to demonstrate and learn more about photovoltaic systems. HECO utilities continue to install photovoltaic systems at Hawaii public schools using voluntary customer contributions and in-kind utility contributions, including engineering, project management, administration, advertising, and marketing. Twenty-four public schools have received photovoltaic systems totaling over 33,000 watts (14 on Oahu, 4 on the Big Island, and 7 in Maui County) including recent installations at Jarrett Middle, Highland Middle, Waianae Middle and Nanakuli Middle schools.

The 2007 estimate includes $40,000 for another Sun Power for Schools photovoltaic installation. HECO will only install photovoltaic systems when the monies collected from voluntary customer contributions are large enough to fund an installation.

Labor

The 2007 estimate includes $104,000 primarily for labor for Technology Division personnel conducting locally-based research and development activities to further HECO's evaluation and implementation of new technologies related to electric utility operations, renewable energy, alternate energy, and emerging technologies.

Overhead

The 2007 estimate includes $76,000 primarily for overhead for Technology Division personnel conducting locally-based research and development activities to further HECO's evaluation and implementation of new technologies related to electric utility operations, renewable energy, alternate energy, and emerging technologies.

Other

The 2007 estimate includes $25,000 primarily for Information Technology services, travel and other activities.

HECO seeks flexibility in the use of R&D funds. In order to meet the requirements of the current Renewable Portfolio Standards law and growing customer needs, new types of technologies will have to be explored and developed. HECO is positioning itself to be even more proactive in the advancement of other new technologies and assessment of revolving and evolving energy policies. Only by assessing the next steps and next technologies through research, development and demonstration (RD&D) can HECO implement new generation technologies and enhance its ability to provide efficient, reliable service to its customers. Activities to position HECO in the long-term (NARUC 921) would include, but would not be limited to, hydrogen energy, fuel cells, advanced energy storage systems, technology related to utility activities and enhancements to demand-side management for peak shaving, reliability, etc., improved customer relations, long-term planning, and other emerging technologies. Some of the state and federal energy policies are renewable portfolio standards, net energy metering, system benefit charges, protecting the environment, reducing impact on customer rates, energy security, carbon emissions, energy credit trading, tax credits, and other energy policies.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OTHER PRODUCTION MAINTENANCE NON-LABOR EXPENSE
2005 ACTUAL VS. 2007 TEST YEAR
($ Thousands)

		(A)	(B)	(C)	(D)
	EXPENSE	2005 ACTUAL	2007 TY ESTIMATE	CHANGE	%
1	Material	$ 9,254	$ 7,738	$ (1,516)	(16)
2	Outside Srvcs/Other	$ 12,442	$ 13,822	$ 1,380	11
3	Transportation	$ 311	$ 360	$ 49	16
4	On-Cost	$ 2,144	$ 2,569	$ 425	20
5	SUBTOTAL	$ 24,151	$ 24,489	$ 338	1
5	Adj & Normalization	$ -	$ (598)	$ (598)	
6	TOTAL	$ 24,151	$ 23,891	$ (260)	(1)

Line 4 - Labor Related On-Cost includes Energy Delivery On-Cost and Power Supply On-Cost.

Line 6 TOTAL: Agrees with HECO-623

HECO T-7
DOCKET NO. 2006-0386

TESTIMONY OF
ROBERT K. S. Y. YOUNG

MANAGER
SYSTEM OPERATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Transmission and Distribution ("T&D") System
T&D Operation and Maintenance ("O&M") Expense
T&D Materials Inventory

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert Young and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the System Operation Department in the Energy Delivery Process Area at Hawaiian Electric Company, Inc. ("HECO" or "Company"). HECO-700 provides my educational background and work experience. I have spent 28 years at HECO in positions involved with the planning and operation of transmission and distribution ("T&D") facilities. These T&D facilities and their proper operation and maintenance are vital to providing reliable service to our customers.

Q. What is your responsibility as a witness in this proceeding?

A. My testimony will cover the following:

1) a brief description of the HECO T&D system;
2) the T&D Operation and Maintenance ("O&M") expense;
3) the reasonableness of the 2007 Test Year estimate, and
4) T&D materials inventory.

Q. Please summarize the 2007 Test Year estimate addressed by your testimony.

A. HECO's estimate for T&D O&M expense for the 2007 Test Year is $35,213,000, as shown in HECO-701. Of this amount, $10,491,000 is for transmission expense and $24,722,000 is for distribution expense, as shown in HECO-702.

Q What is the 2007 Test Year estimate for the T&D materials inventory?

A. The 2007 Test Year estimate for the T&D materials inventory is an average of $6,636,037 and is further detailed in HECO-703.

DESCRIPTION OF THE HECO T&D SYSTEM

Q. Please describe the HECO T&D system.

A. The HECO T&D system begins at the generating plants where electricity is produced. (Mr. Dan Giovanni describes HECO's generation system in HECO T-6.) Electricity generated at these plants is stepped up in voltage at the generator step-up transformers and sent through transmission lines at a nominal 138,000 volts to transmission substations. At the transmission substations, the power is transformed from 138,000 volts to a nominal 46,000 volts and sent through sub-transmission lines to distribution substations. At the distribution substations, the power is transformed to various distribution voltages and sent through lines to our customers. There are a few transmission substations where the voltage is transformed directly from 138,000 volts to nominal distribution voltages of 11,000 volts or 25,000 volts as further explained on page on pages 3 and 4 of my testimony. Distribution lines are located either overhead or underground. HECO-704 provides a diagram illustrating HECO's Power Delivery System.

Q. Please describe in more detail HECO's transmission system.

A. HECO's transmission system is an interconnected electrical network which links HECO's Kahe, Waiau, and Honolulu generating plants, and the major Independent Power Producers (IPP's) at Campbell Estate Industrial Park ("CEIP"), to HECO's distribution facilities. The nominal primary transmission voltage is 138,000 volts, except for the older Honolulu Power Plant, which feeds a 46,000-volt sub-transmission system. There are nineteen transmission substations, one each at Kahe, Waiau and Honolulu generating stations and sixteen other substations located across the island including CEIP, Kalaeloa, AES, Ewa Nui, Wahiawa, Halawa, Koolau, Pukele, Makalapa, Iwilei, School Street, Airport Switching

Station, Airport, Archer, Kewalo and Kamoku. These transmission substations house equipment to transform power (transformers), provide switching and protection (switches, breakers, and relays) and collect data (meters and remote terminal units). The remainder of the transmission system consists of 213.6 circuit miles of overhead lines and 8.3 circuit miles of underground lines. HECO-705 provides a diagram of the transmission system.

Q. Please describe in more detail HECO's distribution system.

A. The nineteen transmission substations feed power to a system of distribution substations through overhead and underground lines that are energized at 46,000 volts. The 46,000 volt lines that carry power to the distribution transformers are referred to as the sub-transmission system. HECO-706 shows the general location of the 46,000-volt sub-transmission lines and distribution substations. HECO's distribution system consists of 125 distribution substations. These distribution substations, and approximately 2,200 circuit miles of overhead and underground lines, connect HECO's electrical system to its customers. These distribution substations transform the voltage to lower nominal voltages (12,470 volts, 11,500 volts, and 4,160 volts) and power is sent through overhead and underground lines to HECO's customers or to distribution transformers. The distribution transformers further reduce the voltage to 120, 208, or 480 volts and power is fed through service lines to customers. There are 265 distribution substation transformers and approximately 32,355 distribution transformers. In addition, three of the nineteen transmission substations directly serve the distribution system.

Q. Please describe how the three transmission substations directly serve the distribution system.

A. The Iwilei, Kewalo and Kamoku transmission substations transform voltage from

138,000 volts to a distribution voltage of 25,000 volts and send this power through underground lines directly to distribution transformers on the customer's property. Transforming the voltage at the transmission substation eliminates the need for distribution substations and associated land acquisitions and, at this higher voltage, reduces the number of lines required to serve an area. This system works well in areas of high load concentrations where available land is scarce and is currently being developed; such as the Ala Moana, Kakaako and Kapiolani areas in Honolulu. The Iwilei substation also serves the downtown network and transforms the 138,000 volts directly to a distribution voltage of 11,000 volts.

T&D O&M EXPENSE

Q. Please summarize the 2007 Test Year estimate of T&D O&M expense.

A. HECO's estimate of T&D O&M expense for the 2007 Test Year is $35,213,000 as shown in HECO-701. Of this amount, $10,491,000 is for transmission expense and $24,722,000 is for distribution expense, as shown in HECO-702.

Q. Did HECO make any adjustments to its 2007 T&D O&M Expense Budget to develop its 2007 Test Year expense estimate?

A. Yes, adjustments to the 2007 T&D O&M Expense Budget are shown in HECO-WP-710 and are incorporated into 2007 Test Year expense estimates represented in the T&D O&M exhibits as referenced in this testimony. The adjustments to the O&M expenses were due to 1) removal of performance incentive compensation costs; 2) additional costs for abandoned projects; and 3) a correction for a double counting in the Customer Service Department. A discussion of the abandoned projects and the performance incentive compensation costs is provided by Patsy Nanbu in HECO T-10. The costs of abandoned capital projects (where a "no go" decision is made during the time project costs are classified as Construction Work in Progress) are generally written off to appropriate operation and maintenance expense accounts. The adjustments for the abandoned projects reflect the write off of the abandoned project costs to the appropriate operation and maintenance account.

Although performance incentive compensation costs are appropriate costs of doing business, the Company adjusted its O&M Expense Budget for performance incentive compensation costs to reduce the number of issues in this case. The Company has not waived its right to seek recovery of these costs in future rate cases.

- Transmission Operation non-labor expense was reduced by $37,000. The $37,000 is the net of a $2,000 positive adjustment for abandoned projects less $39,000 for the removal of performance incentive compensation costs.
- Transmission Maintenance non-labor expense was increased by $21,000 for abandoned project costs.
- Distribution Operation Labor O&M expense was reduced by $68,000 to correct for a double counting in the Customer Service Department. The Department forecasted for outside contractor costs and a HECO position for revenue protection work. This adjustment is being made to correct for this double counting.
- Distribution Operation non-labor expense was adjusted by a net of $10,000. The $10,000 adjustment resulted from an addition of $111,000 for abandoned projects less $101,000 for the removal of performance incentive compensation costs from the O&M budget.
- Distribution Maintenance non-labor expense was adjusted by $12,000 for abandoned projects.

In aggregate, Transmission Operation and Maintenance expense was reduced by $16,000 and Distribution Operation and Maintenance expense was reduced by $46,000. Please refer to Patsy Nanbu's testimony in HECO T-10 for further information regarding abandoned projects and performance incentive compensation costs.

Q. Did HECO incur any expenses recorded in 2005 that are not attributable to work performed in 2005?

A. Yes, in late 2005, HECO learned that both labor and non-labor charges for some transmission maintenance and distribution operations & maintenance work performed in 1999 through 2005, primarily by the Construction & Maintenance Department, had been incorrectly charged as capital work.

To determine the extent of the incorrect charges for work that occurred in the years 1999 through 2005, the Construction & Maintenance, Engineering, and Customer Installations Departments commenced an extensive research effort on charges in these work orders to determine the extent of the incorrect charges. Based on the results of research efforts by the Departments, expense-related charges previously capitalized were reclassified to O&M expense in 2005, resulting in an increase in T&D O&M expense of approximately $3.4 million of which approximately $3 million related to the years 1999 to 2004. Adjustments to capital, AFUDC and depreciation were also recorded. The correction to accurately reflect the work performed in 1999-2004 as O&M expense was made to the fiscal year 2005, resulting in a 2005 recorded O&M expense of $3,030,270 that represents work performed in years other than 2005. The work performed in 2005 was adjusted during the same fiscal year, to accurately report the work as 2005 O&M expenses. Therefore the adjustment for work performed in 2005 correctly reflects in both the O&M and Capital accounts in 2005. In 2005, procedures were implemented to prevent this type of oversight from reoccurring. The $3,030,270 cost transfers from capital to T&D O&M expense, correlated with the year in which the work was performed, are outlined on HECO-727. Since the adjustments were immaterial to HECO's quarterly financial statements, including the impact to the previous quarters, a restatement of HECO's prior periods' financial statements was not necessary.

Q. How does HECO plan to represent the actual work performed in 2005 recorded T&D O&M expenses?

A. An adjustment has been made to the 2007 Test Year exhibits to deduct $3,030,270, the amount that represents work performed prior to 2005, from the 2005 recorded expenses for purposes of calculating and comparing 2005 recorded expenses to 2007 Test Year estimates. The adjustments to 2005 T&D O&M recorded expenses are shown in HECO-734.

Q. Did HECO make adjustments to its planned work as a result of this one time adjustment for the work order corrections to mitigate the impact on 2005 O&M expenses?

A. As indicated above it was not until late 2005 that the amount to be charged to the 2005 O&M expenses was known. However, once it was understood that a work order adjustment would need to be made, an effort was made to manage certain costs (primarily overtime expenses) so as to reduce the impact of this adjustment on 2005 O&M expenses. In addition, in the System Operation Department, personnel already were being used to perform capital work for the Ford Island and Kuahua substations and the new EMS / New Dispatch Center projects and other capital projects. The EMS project in particular required a large number of System

Operation resources such that they were charging their time to this capital project instead of O&M. In the short-term, we were able to temporarily manage the O&M workload by prioritizing the work that needed to be completed in 2005. The temporary measures that were taken did not impact service to HECO's customers. Based on HECO's reliability results for the years 1989-2005, as shown in Exhibit HECO-718, HECO's SAIF for 2005 of 1.32 was not the lowest HECO has ever achieved, but it was comparable to the 2004 result of 1.27.

Q. How does the 2007 Test Year estimate of T&D O&M expense compare to previous years?

A. HECO-707 shows HECO's T&D O&M expense from recorded 2001 through the 2007 Test Year estimate. The 2007 T&D O&M Expense Test Year estimate is higher than adjusted 2005 by approximately 26%.

Test Year Estimates

Q. How was the 2007 Test Year estimate of T&D O&M expenses derived?

A. Each responsibility area ("RA") within a department determines the O&M work required to maintain and operate the system to provide reliable electric service to HECO's customers. This level of work is based on a combination of inspection cycles, units of work, number of operations (i.e., the amount of times the equipment operated), historical trends, and is budgeted by staff with working knowledge of the maintenance requirements for HECO's facilities and the operation of the electrical system. Starting with the available labor resources (i.e., the staffing level) each RA then allocates the labor man-hours to the planned work and non-labor costs to activities corresponding to the operation or maintenance work that has been planned for the year. Each department also forecasts the non-labor costs for the level of work planned for the year. These non-labor estimates are for materials and outside services that are required for the year. Where estimates are provided or if an inflation factor is known that can be used to calculate the future costs of the non-labor item then these costs are used to produce the budget. Each activity is linked to National Association of Regulatory Commissioners (NARUC) account numbers. This initial process resulted in the 2007 O&M Expense Budget. An internal review process is conducted with the company officers, after which there is an opportunity to review the budget and refine the figures in the budget. Using the 2007 O&M Expense Budget as a starting point, adjustments are made to develop the 2007 Test Year Estimate of O&M expenses.

Q. When referring to the O&M work required for maintaining and operating the system; can you provide a description of some of the work that is done by HECO?

A. Exhibit HECO-738 contains descriptions of Construction & Maintenance ("C&M") department's programs. This list is not meant to be all inclusive, as other departments such as System Operation also work to maintain and operate the system but does not organize them into programs. Instead System Operation relies on information such as number of times the equipment operated, inspections, infrared scans, tests, trends and other factors to determine its work for the year and going forward. There is going to be more variability in determining the expected work because System Operation relies on factors such as the number of times the equipment operated.

Q. How is the direct labor cost calculated?

A. Starting with personnel resources that are available, labor hours (estimated as man-hours) are allocated to perform the planned work. The man-hours are converted to direct labor dollars when multiplied by appropriate standard labor wage rates in the

Pillar System.

Q. What is the impact of general wage increases included in the 2007 budget?

A. On an annual basis, general wage rates for Test Year 2007 are expected to be 6.53% (for bargaining unit employees) and 7.64% (for merit employees) higher than the respective 2005 wage rates (see HECO-1005).

Q. How are wage increases determined for bargaining unit positions for the test year?

A. Wage increases for bargaining unit positions are negotiated between the Company and the union. The current labor agreement expires on October 31, 2007. For purposes of the 2007 budget and the test year estimate, wages for bargaining unit positions were increased by 3.5% effective November 1, 2007. Discussion of the wage increase estimate is covered by Ms. Julie Price in HECO T-12.

Q. How was the 2007 salary increase budget determined for merit positions?

A. For merit employees, wage rates increased by an average of 3.5% on May 1, 2005, 0.25% on September 1, 2005. Merit wage rates are estimated to increase by 3.5% effective May 1, 2006, 0.25% effective September 1, 2006 applied to merit wages as of April 30, 2006 and 3.5% effective May 1, 2007 and 0.25% effective September 1, 2007 with the percentage increases being applied to merit wage rates as of April 30, 2007.

Q. How are direct non-labor costs budgeted?

A. Direct non-labor costs reflect estimates for materials, information system services and contracts and services. These costs are budgeted in dollars and represent the non-labor requirements necessary to support the work that needs to be performed. These budgeted dollars include known increases for non-labor requirements as well as an appropriate inflation adjustment of 2.5% in 2007 or known inflation adjustment provided by a vendor. Please refer to Patsy Nanbu's discussion of this assumption in HECO T-10 as well as for a discussion on the impact of the general wage increase.

Q. Does the T&D expense estimate include only the direct labor and direct non-labor?

A. No. Overhead costs or on-costs charges are applied to direct T&D labor and non-labor expenses. These overhead costs include related indirect expenses such as Energy Delivery Process Area (EDPA) supervision and administrative costs as well as non-productive wages. Therefore, total T&D expense is the sum of direct labor costs, direct non-labor costs and applicable overhead costs as described by Patsy Nanbu in HECO T-10.

Q. What information does the Company provide to explain the 2007 expense increases?

A. In addition to the impact of the general wage increases and the impact of the appropriate inflation adjustment, the increases are addressed in this testimony under the headings of Transmission Operation, Transmission Maintenance, Distribution Operation, and Distribution Maintenance, with further details included in the Reasonableness of Test Year Estimate section of this testimony. In addition, HECO-WP-705 provides explanations of 2007 Test Year expense items that exceed 2005 test year recorded amounts by $200,000 and 10%.

Q. What impact, if any did the programs have on HECO's 2007 Test Year estimate of O&M expense?

A. Exhibits HECO - 735 and HECO - 736 were prepared to show the change in program expenses between 2005 and 2007 and what it contributed to the 2007 Test Year T&D O&M expenses. HECO-736 shows the 2001 to 2005 actual expenses, 2006 Budget, and 2007 test year estimate. Upon examination of the actual program expenses for years 2001 to 2005 one can see that there is some variability between years. As an example, for program P0000360 Preventive Maintenance of T&D System expense varied from $778,021 in 2001 to $117,500 in 2004. One reason for this variability is that with information gathered during inspections or as other information with respect to the system is received by the C&M Department, adjustments are made to what work will be done to address priority items. These changes in the work will impact the programs if the work in one program is postponed so that work in another program can be done. Another example is in 2004 program Preventive Maintenance – T&D System expenses (P0000360 Preventive Maintenance of T&D System) decreased from $117,500 to $94,322 while program Corrective Maintenance - T&D system expenses (P0000359 Corrective Maintenance of T&D System) increased significantly over the prior year from $2,476,398 to $4,047,311. Based on the description of the programs, one can presume the C&M crews shifted from preventive maintenance work to corrective work that might have been brought on by outages or equipment problems that needed to be addressed on a priority basis. Accordingly some of the preventive work may have been postponed or cancelled because work was necessary to address the corrective work.

Exhibit HECO-735 is provided to show the change in program costs between 2005 recorded and 2007 Test Year estimates. Exhibit HECO-735 reflects that some program expenses have increased and others decreased. As discussed earlier, there can be variability on costs for a program based on the work that is planned, from one year to the next. Therefore, conclusions regarding the level of work that should be done within a program that is based on merely looking at a trend of the recorded expenses may not be entirely accurate. For example, the information we obtain from our inspections, information that we did not know earlier, is a factor that affects the level of work we will end up spending for a particular program. There are also times when the information we obtain from our inspections which may require corrective action may not be performed in the same year we obtained such information. With respect to our corrective programs, we have also to rely and take into consideration, our work experience, system knowledge and judgment to develop the expenses. It should be also noted that although capital replacement projects improves the reliability on our system, it still does not replace the need for corrective programs which are needed throughout our electric system.

Q. What items are included in HECO's T&D O&M Expense?

A. T&D O&M Expense includes the labor and non-labor expenses incurred in the operation and maintenance of HECO's T&D system. These expenses are recorded in the following accounts as defined by the NARUC Uniform System of Accounts for Classes A and B Electric Utilities.

560-567	-	Transmission Operation Expenses
568-573	-	Transmission Maintenance Expenses
580-589	-	Distribution Operation Expenses
590-598	-	Distribution Maintenance Expenses

HECO-WP-701, HECO-WP-702, HECO-WP-703, and HECO-WP-704 provide descriptions of the expenses that are included in these NARUC accounts.

TRANSMISSION O&M EXPENSE

Q. What is HECO's 2007 Test Year estimate of Transmission O&M expense?

A. HECO's 2007 Test Year estimate of Transmission O&M expense is $10,491,000 as shown in HECO-708.

Transmission Operation Expense

Q. What is HECO's 2007 Test Year estimate for Transmission Operation expense?

A. HECO's 2007 Test Year estimate for Transmission Operation expense is $5,378,000 as shown in HECO-708.

Q. What items are included in Transmission Operation expense?

A. Transmission Operation expense includes labor and non-labor costs as shown in HECO-709 to support activities such as load dispatching and transmission switching operations, transmission substation inspections and operations, communications systems operations and inspections and transmission line, pole, and structure inspections. The corresponding NARUC account numbers for Transmission Operation are detailed further in HECO-WP-701.

Q. How does the 2007 Test Year estimate of Transmission Operation expense compare to previous years?

A. HECO-710 shows HECO's Transmission Operation expenses from recorded 2001 through 2005, 2006 budget and the 2007 Test Year estimate. These expenses have increased in the 2001-2005 period. The 2007 Test Year estimate is $1,407,000 higher than the recorded 2005 Transmission Operation expense.

Q. Please explain what factors contributed to the $1,407,000 increase.

A. The $1,407,000 increase in Transmission Operation expense compared to 2005 is the result of the following:

1) General wage increase and non-labor expense inflation.
2) Higher labor costs in the operating area of the System Operation Department due to more personnel in the Operating Division.
3) Increased transmission inspections that are necessary because of the aging transmission assets.

<u>Transmission Maintenance Expense</u>

Q. What is HECO's 2007 Test Year estimate for Transmission Maintenance expense?

A HECO's 2007 Test Year estimate for Transmission Maintenance expense is $5,113,000 as shown on HECO-708.

Q. What items are included in Transmission Maintenance expense?

A. Transmission maintenance expense includes labor and non-labor costs as shown in HECO-709 to support activities such as maintenance and repairs related to transmission substation equipment and facilities, communications equipment, transmission lines and cables, and tree trimming. The corresponding NARUC account numbers for Transmission Maintenance are detailed further in HECO-WP-702.

Q. How does the 2007 Test Year estimate for Transmission Maintenance expense compare to previous years?

A. HECO-710 shows HECO's Transmission Maintenance expenses from recorded 2001 through 2005, 2006 budget, and the 2007 Test Year estimate. The 2007 Test Year estimate is $1,400,000 higher than the adjusted 2005 recorded Transmission Maintenance expense.

Q. Please explain what factors contributed to the $1,400,000 increase.

A. The $1,400,000 increase in Transmission Maintenance expense compared to 2005 is the result of the following:

1) General wage increase and non-labor expense inflation.
2) Increased vegetation management program expenses to deal with substantial growth in vegetation around HECO's transmission line corridors and sub-transmission lines.
3) A greater amount of maintenance work that was identified by inspection programs for HECO's aging transmission and sub-transmission system and substations.

4) A corresponding increase in the non-labor expenses for the parts and equipment required to support the increased maintenance work.

5) Staffing increases in various departments.

6) Costs related to the maintenance of the new Siemens Energy Management System (EMS).

7) A reclassification of labor charges from Capital to O&M expenses. HECO personnel resumed their normal work O&M activities after having worked on and completing the new EMS and new Dispatch Center Capital Project. To provide some background, seven employees (primarily from the Operating Engineering group in System Operation) were tasked to support and implement the new EMS. A majority of their time was spent to complete the project. This group of employees were augmented by employees from other divisions in System Operation to work on the related systems such as the installation and testing of the communication lines, testing and reconnecting the existing remote terminal units (RTU's) at the transmission substations and the power plants and the implementation and testing of the Siemens EMS. At that time, support for the old Rockwell EMS was limited only to activities that were essential to support operations requirements and to ensure the reliability of the EMS. Thus, O&M expenses during this period were lower, as only a part of their time was spent to support the old Rockwell EMS.

DISTRIBUTION O&M EXPENSE

Q. What is HECO's Test Year estimate of Distribution O&M Expense?

A. HECO's Test Year estimate of Distribution O&M Expense is $24,722,000 as shown in HECO-711.

Distribution Operation Expense

Q. What is HECO's 2007 Test Year estimate of Distribution Operation expense?

A. HECO's 2007 Test Year estimate of Distribution Operation expense is $10,661,000 as shown in HECO-711.

Q. What items are included in Distribution Operation expense?

A. Distribution operation expense items include labor and non-labor costs as shown in HECO-709 to support activities such as trouble dispatching and distribution switching operations, distribution substation inspections and operations, distribution line, pole and structure inspections, connecting, disconnecting and locking meters, and investigating customer complaints. The corresponding NARUC account numbers for Distribution Operation are detailed further in HECO-WP-703.

Q. How does the 2007 Test Year estimate for Distribution Operation expense compare to previous years?

A. HECO-712 shows HECO's Distribution Operation expenses from recorded 2001 through 2005, 2006 budget and the 2007 Test Year estimate. These expenses have increased over the 2001-2005 period. The 2007 Test Year estimate is $1,857,000 higher than the adjusted 2005 recorded Distribution Operation expense.

Q. Please explain what factors contributed to the $1,857,000 increase.

A. The $1,857,000 increase in Distribution Operation expense compared to 2005 is the result of the following:

1) General wage increase and non-labor expense inflation.
2) Staff additions to operate and inspect distribution overhead facilities to maintain and possibly improve system reliability.
3) Distribution substation inspections that are being done in conjunction with

the guidelines for the PDM (predictive maintenance) program.

Further discussion of staffing increases is covered later in my testimony.

Distribution Maintenance Expense

Q. What is HECO's 2007 Test Year estimate of Distribution Maintenance expense?

A. HECO's 2007 Test Year estimate of Distribution Maintenance expense is $14,061,000 as shown on HECO-711.

Q. What items are included in Distribution Maintenance expense?

A. Distribution maintenance expense includes labor and non-labor costs as shown in HECO-709 to support activities such as maintenance and repairs to distribution substation equipment and facilities, distribution lines and cables, tree trimming, and testing and treating wood distribution poles. The corresponding NARUC account numbers for Distribution Maintenance are detailed further in HECO-WP-704.

Q. How does the 2007 Test Year estimate for Distribution Maintenance expense compare to previous years?

A. HECO-712 shows HECO's Distribution Maintenance expenses from recorded 2001 through 2005, 2006 budget and the 2007 Test Year estimate. The 2007 Test Year estimate is $2,706,000 higher than the adjusted 2005 recorded Distribution Maintenance expense.

Q. Please explain what factors contributed to the $2,706,000 increase.

A. The $2,706,000 increase in Distribution Maintenance expense compared to 2005 is the result of the following:

1) General wage increase and non-labor expense inflation;
2) Increased vegetation management program expenses to deal with substantial growth in vegetation around HECO's distribution lines;

3) Increased programs to test and treat wood distribution poles;

4) Increased maintenance of distribution substations resulting from inspections that were conducted; and

5) Costs related to the maintenance of the new technology addition of the Outage Management System.

REASONABLENESS OF TEST YEAR ESTIMATE

Reasonableness of T&D O&M Increases

Q. How is HECO's T&D O&M expense expected to increase after 2005?

A. Total T&D O&M adjusted expense was $27,843,000 in 2005 as shown in HECO-707. This expense is budgeted to increase by $7,370,000 to $35,213,000 in the 2007 Test Year, as shown in HECO-707.

Q. Why is the T&D O&M expense for the 2007 Test Year expected to increase?

A. The 2007 Test Year estimate for T&D O&M expense is expected to increase due to:

1) new system operation technology: EMS / OMS systems[1];
2) increase in vegetation management requirements;
3) increase in work resulting from inspections of the T&D system;
4) increase in inspections and maintenance for aging T&D plant;
5) growth in the T&D utility plant additions;
6) system reliability improvements;
7) increase in staffing; and
8) increases in wages and non-labor expense.

[1] (The Commission approved the Company's applications for these systems in Decision and Order No. 21224 issued on August 6, 2004 in Docket No. 03-0360 and Decision and Order No. 21899 issued on June 30, 2005 in Docket No. 04-0131.

1) New System Operation Technology

Q. What is the Siemens Energy Management System (EMS)?

A. The new Siemens EMS replaced HECO's 20+ year old EMS from Rockwell Systems International. Over the years, the performance of HECO's old Rockwell EMS degraded in spite of HECO's best efforts to maintain the performance of the Energy Management System. As the years passed, the computer equipment and other components that were used for the Rockwell EMS became obsolete. This situation made it difficult to keep the Rockwell EMS operational as third party equipment suppliers needed to be found that could provide new, used, or refurbished parts for the old equipment. Upon receiving Commission approval, HECO replaced the old Rockwell EMS with the new Siemens EMS. Refer to Decision and Order No. 21224 issued on August 6, 2004 in Docket No. 03-0360. The new EMS's performance is comparable to industry standards and includes additional functionality such as a Dispatcher Training Simulator, a State Estimator, and an on-line contingency analysis program. The new EMS will improve HECO's ability to respond to electrical system events and provides a crucial environment to train the dispatchers to respond to system emergencies without putting the electrical system at risk.

Q. Please describe how the EMS new technology project impacts T&D O&M expenses.

A. HECO's Transmission Maintenance expense for the 2007 Test Year estimate will increase by $387,000 from the 2005 recorded expense associated with maintaining the old Rockwell system, to provide for the on-going maintenance cost associated with the new EMS. Unlike the predecessor Rockwell EMS, the new Siemens EMS is a vendor supported system. With this vendor support, the EMS software is updated periodically as program improvements or modifications are made to the base EMS software; hence the system is kept current with the updates to the software version. This software maintenance program also provides for software upgrades that incorporate new releases of the EMS software. A new software release typically occurs once every 18 months and represents an upgrade of the EMS to a newer version with improved functionality. Additionally, similar to "help desk" support, Siemens provides 7 day by 24 hour technical support to HECO personnel to assist in the resolution of major problems that cannot be solved solely by HECO personnel. This support is especially critical given the extremely important operational function of the EMS.

HECO did not pay any vendor software maintenance costs for the old Rockwell system because Rockwell pulled out of the energy management system market shortly after completing the sale to HECO. Without a vendor to continue development, HECO could only provide support by the internal staff and could only purchase support for the computer operating system and maintenance support for the hardware. Because the system was antiquated, HECO did not invest in software development or upgrades to the Rockwell system since 1999. The 2005 recorded expense for hardware maintenance associated with the Rockwell system was $170,000. With the EMS implementation, the prior Rockwell maintenance expense is no longer incurred and offsets the new EMS maintenance total cost of $557,000. The increase in maintenance cost over the $170,000 of the previous Rockwell EMS maintenance cost is accounted for in the $387,000 increase attributed to new EMS technology. HECO's staff which was engaged in overseeing the old Rockwell system is now administering the new EMS system.

Q. Does the $387,000 increase to expenses include costs associated with the new

Siemens EMS other than software maintenance costs?

A. Yes, in addition to the software maintenance costs, HECO is paying another vendor for computer equipment maintenance support. Computer equipment maintenance support provides for repair or replacement of computer equipment and peripheral equipment (such as printers, switches, and routers) when there is a problem. In addition, 7 days by 24 hour technical support is provided to assist HECO personnel with trouble shooting hardware related issues. In addition to the EMS computer and peripheral equipment this amount includes a fee for the maintenance support of the new dynamic video wallboard that includes the cost of replacement bulbs and technical support for the wallboard equipment.

Q. Why do you expect to see a reclassification in labor charges from capital expenditures to O&M expenses in 2007 when compared to 2005?

A. During the implementation of the new Siemens EMS, many System Operation Department employees were required to support the project. The labor hours spent on the EMS project were charged as capital. One division, the Operating Engineering Division normally worked primarily on O&M activities to support the old Rockwell EMS but during the project the O&M work was limited to ensuring that the old Rockwell system could function and could meet the operational needs thus lowering the O&M expenses incurred in 2005.

The following groups in the System Operation Department assisted with implementing the new Siemens EMS project:

- Communications personnel (6 employees)
- Operating Engineering staff (7 employees or the entire EMS Support Staff)
- the Instrument and Control group, to support the remote terminal

units (RTU's that communicate information from the substations to the EMS; (3-4 employees)

- Substation and Relay personnel (3 to 4 employees when necessary to meet the project deadlines)

Their activities included installing new communication lines to connect the RTU's to the new Siemens EMS; testing the RTU's on the new Siemens EMS; performing factory acceptance and site acceptance testing of the EMS; converting the Rockwell database to the Siemens database; validating supervisory control functions (e.g., opening and closing breakers, checking that values from the substation sites were correct); tuning the generator control functions; and many more activities associated with successful implementation of the EMS.

At the completion of the EMS project, the Operating Engineering Division staff, who had been charging work to the EMS capital project resumed work to maintain the Siemens EMS which is an O&M expense. The other groups, Communication, Substation, Instrument and Control, and Relay, returned to their normal work that consists of both capital and O&M.

Q. Please identify what the Outage Management System ("OMS") project is.

A. The OMS Project involves the purchase and installation of a new, commercially available, OMS, including purchase, configuration and testing of the software for the new system, purchase and installation of related hardware, conversion and "cleansing" of data (i.e., making sure the data that is converted is accurate and in the correct format), development and testing of interfaces between the new system and other HECO systems, including the Customer Information System ("CIS"), the Automated Mapping / Facilities Management ("AM/FM") mapping system, the Interactive Voice Response system, and the Energy Management System ("EMS") and associated training for HECO employees.

Q. What does the OMS software do?

A. An OMS is an information technology system that has capabilities that include collecting trouble call information for the purpose of determining, through predictive analysis, the most probable device that is causing the outage and its location, providing status updates of an outage, identifying work crews capable of addressing the outage, scheduling and dispatching work orders to the field, managing field personnel addressing the outage, and providing historical outage data and reports. Currently, HECO does not have an OMS. The OMS will take many of the functions now performed manually by HECO and provide the support system to automate these functions. This will allow the dispatcher to focus on the primary task of restoring power to customers as quickly and safely as possible.

HECO generally classifies power outages as either (1) unplanned or (2) planned. Planned outages occur when an area is de-energized so that HECO crews can safely work to maintain, expand, modify, repair and improve the electrical system. When arranging planned outages, the OMS will identify which customers will be impacted in the area where the work will be performed, assist dispatchers in preparing switching operations that are necessary to provide a safe clearance area, and display updates on the status of the outage so that such updated information can be provided to customers that call concerning the planned outage.

Unplanned outages are commonly caused by weather, equipment faults or automobile accidents. With respect to unplanned outages, the OMS will automate certain manual processes that HECO uses to identify and locate the source of an electrical outage, provide information to assist HECO's dispatchers in managing the field personnel restoring electrical power, update the status of an outage, and disseminate such information internally -- particularly to HECO's Customer Service and Energy Services personnel -- so that updated information (e.g., extent of the outage and the estimated time to restore power) can be provided when customers call concerning the outage.

Q. Please describe the OMS project's expected benefits.

A. The automation that the OMS provides will allow HECO personnel more time to concentrate on restoring power to HECO's customers rather than managing the flow of papers or trouble tickets that are currently used for assessing and managing outages. The OMS Project will assist HECO's dispatchers in dispatching and managing the repair crews to locations where repairs are necessary with the intent being to restore power to the customers as quickly and as safely as possible. The OMS Project will also be able to display the status of an outage and produce historical outage data and reports. In addition, the OMS will be a valuable tool for communicating the impact of an outage to internal groups, who can then pass on this information to HECO's customers during unplanned outages and planned outages, as the system will be capable of quickly disseminating updates of the status of outage incidents (e.g., estimated time to restore power, when power was restored, or a delay in the restoration, etc.). HECO personnel will find this extremely valuable as they receive requests for updates from their customers, so that HECO's customers (i.e., commercial, military and residential customers) can make their own plans on what they need to do to respond to the outage incident.

In either outage scenario (unplanned or planned outages), the information that the OMS can provide will be readily available to the dispatchers on the electronic map displayed in the dispatch office on the wallboard and the computer monitors. The information will also be available to the Customer Service

Representatives ("CSR's"), as well as others in HECO requiring this information. The goal is to ensure that the information about the extent of the outage and the estimated time to restore power is made in terms that are informative to the CSR and customers.

Q. What is the current status of the OMS project at HECO?

A. Currently, HECO and SPL Worldgroup personnel have developed the configuration requirements for the software and have completed the factory acceptance testing of the software. The next step in the project plan is to complete the site acceptance testing of the software, which is scheduled for January 2007. Upon successful completion of the site acceptance test in January, HECO personnel will then begin training on the new system. When site acceptance occurs in January, all substantial testing would be complete and the OMS software will be ready for its intended use. Training of HECO personnel to properly use the system in daily operations would then commence. It is targeted for the training to be complete and the new OMS system in service for the dispatchers to respond to outages in mid to late May 2007.

Q. How are the project costs being treated?

A. By the Commission's Decision and Order No. 21899 dated June 30, 2005 in Docket No. 04-0131, the commission approved the Company's request (as modified by the stipulation with Consumer Advocate) to defer certain software development costs for the OMS project, accumulate AFUDC on the deferred costs during the deferral period, amortize the deferred costs over a twelve year period and to include the deferred costs in rate base. Cost for the OMS project are accounted for in accordance with the Company's Computer Software Development policy, which is described by Ms. Patsy Nanbu in HECO T-10. Generally, software development costs are segregated into three stages: (1) Stage 1, Preliminary; (2) Stage 2, Application Development; and (3) Stage 3, Post Implementation/Operation. Depending on the stage on which costs are incurred, the OMS project costs will be either expensed or capitalized (i.e., deferred). Stage 1 costs are expensed, Stage 2 costs are generally capitalized, however certain training costs, as well as certain conversion costs are charged to expense, and Stage 3 costs are expensed. An AFUDC expense is applied to the deferred project costs during Stage 2 and that the deferred costs will be amortized over a twelve year period.[2]

Q. What are the total costs of the OMS project?

A. The 2007 budget and test year estimates were developed under the assumptions that (1) the deferred OMS project costs (including AFUDC) would amount to $4,247,000, (2) the software would be ready for use in March 2007, and (3) amortization of the deferred costs over twelve year period would begin in April 2007. The amortization expense from April through December 2007 was estimated to be $258,000. The unamortized costs as of the end of the year was estimated at $3,989,000, as shown on HECO-1017.

However, a more current estimate of the cost is provided in HECO-737. The current estimate reflects the deferred OMS project costs (including AFUDC) to amount to $4,232,000. As discussed above, the site acceptance is expected to occur in January 2007, at which time the software will be ready for its intended use. The amortization is scheduled to begin in February 2007, and the amortization expense is estimated to be $300,000 for 2007. See HECO-WP-711 for the

[2] See Decision and Order No. 21899 in Docket 04-0131dated June 30, 2005 at page 7 for a description of the proposed accounting treatment.

calculation of the amortization expense for the year. The unamortized costs at the end of the year is estimated at $3,931,000

Q. Referring to HECO-WP-711, why are costs being budgeted to be deferred after January 2007, when the software is expected to be ready for its intended use?

A. During negotiations with SPL on the statement of work (SOW)[3] a payment schedule was developed for the software license costs, software implementation services milestone costs and the cost of the annual maintenance agreement. The schedule for the software license payments and the milestone payments for the software implementation services is based on a 24 month period that extends beyond the current in-service date January 2007. As a result the costs generally refer to software license costs and fees for software implementation that will continue to be charged to the deferred debit account beyond the January 2007 date, as the invoices are paid. Note that the portion of the payments related to maintenance fees will be charged to expense.

Q. How was the amortization expense calculated, given costs continue to deferred after the amortization period begins?

A. The February 2007 deferred balance is divided by 144 months to straight-line the monthly amortization expense over 12 years. As additional deferred costs are projected to be paid in the months of February 2007 through September, 2007, those specific monthly amounts are also calculated on a straight-line amortization basis. However, for those deferred costs incurred from February, 2007 through September, 2007, each projected month's deferred expense is reduced from the

[3] The referenced payment schedule was provided to the Commission under Protective Order No. 21430 as page 171 of 172 of Exhibit 1 that was attached to HECO's interim supplemental report providing the name of the contractor selected, the scope, functional requirements and cost of the OMS project dated August 22, 2005, Docket No. 04-0131.

complete 144 months (of amortization) by the respective number of months that will have passed beyond the amortization start date of February, 2007, to calculate the straight-line amortization amount to be applied to the remaining months within the 12 year stipulation.

Q. Are there other expenses for the OMS besides the monthly amortization expense that will impact T&D O&M expenses?

A. HECO's Distribution Maintenance expense increased by $113,520 in 2007 to provide for the on-going maintenance cost associated with the new OMS as shown in Exhibit HECO-737. As this is the first implementation of an OMS at HECO there were no costs for O&M maintenance support in prior years. The vendor, SPL, will be providing software maintenance support for the OMS. Additionally, as mentioned later in this testimony a person was hired for a position in the System Operation Department to support the OMS. The discussion in the Staffing section of this testimony explains the need for the employee.

Additionally, training costs of $453,000 will be incurred to train HECO personnel on the use of the SPL OMS. Of the $453,000 approximately $27,000 is for a consultant to assist HECO with tailoring the training materials to HECO's operating procedures while fully utilizing the functionality provided by the SPL OMS. Though SPL has instructors familiar with the functionality of the software they lack operating experience. Having a consultant with an operating background and with knowledge of the OMS functionality will ensure that more realistic training plans are developed and hence the dispatchers will be better able to adapt to using the new OMS.

Q. Was an adjustment made to the 2007 Test Year T&D O&M estimate to reflect the addition of - $42,000 in OMS amortization expense for February and March, 2007?

A. No. Because there is some variability in the OMS project schedule, the Test Year estimate was not revised when the site acceptance date was advanced to January, 2007.

Q. What does the software maintenance support agreement from SPL provide?

A. Similar to the Siemens EMS support agreement, the SPL Worldgroup software maintenance support agreement provides for the periodic OMS program updates that will address software bugs as well as upgrades to the software. These upgrades will ensure that the software is kept current with new or improved functionality as well as provide for changes to the software that are required as a result of operating software system upgrades.

Q. Is there going to be a shift between capital and O&M expenses for the OMS project?

A. No, unlike the EMS, the OMS is implementation of new software. As a result, a deferred debit account was created to capture the expenses for the implementation of the software. Other costs for the project, for example the hardware costs, data clean-up, and training, will be treated as described in Decision and Order No. 21899 in Docket No. 04-0131, dated June 30, 2005, "Proposed Accounting Treatment" at page 7.

<u>2) Vegetation Management</u>

Q. What has contributed to the need to increase HECO's vegetation management program?

A. HECO's vegetation management program is designed to keep the transmission corridors (138,000 volt lines) clear of vegetation that might come into contact with the transmission lines and to prevent outages to the sub-transmission (46,000 volt) lines, as shown in HECO-705 and HECO-706. The transmission and sub transmission overhead lines are the lifeline of Oahu's electrical system. Keeping these corridors clear from vegetation threats is essential to mitigate cascading adverse events on the transmission system that could potentially lead to a major outage or even an island-wide black-out.

The impact of vegetation on the distribution system has a direct effect on HECO's customers as they will experience either a momentary or sustained interruption to their electrical service. There have been instances in the past when customers experienced multiple interruptions, some momentary and some sustained, that were the result of vegetation incursions on the system facilities. These incidents occur when there is direct contact between a tree branch and a circuit. Most momentary outages are the result of the wind blowing tree branches or fronds into close proximity to the line such that an arc is created between the branch and the circuit. These momentary outages are more difficult to find because the tree branch or frond may not show signs of electrical arcing, the inspectors have to judge whether or not there might have been contact. It is essential to sustain a vegetation management program that adequately mitigates the risks of vegetation encroachments to HECO's lines and facilities, to ensure service reliability and to prevent customer complaints.

Beginning in October, 2003, statewide precipitation began increasing over the previous decade. In March, 2006, rainfall on some Oahu sites exceeded 500% of normal. Precipitation indices as reported by NOAA (National Oceanic & Atmospheric Association) show that during the last three winters, 2003-04, 2004-05, and 2005-06, there was above normal precipitation across the state. As shown in HECO-728, annual precipitation in 2000, 2001, & 2002 was less than normal rainfall at all reported locations on Oahu. Hawaii has been in a wet cycle since

November 2003. Prior to that, the State experienced about 12 years with less active winter seasons and normal or below normal precipitation for most of that time. This wet cycle trend is consistent with the significantly above normal rainfall data collected from across the State in 2004, as shown in HECO-728. Oahu experienced approximately 40 days of rain in March and April 2006, reflected in August 2006 year-to-date precipitation data again recording much higher than normal rainfall. HECO-729 shows the 2006 August year-to-date precipitation by location depicted on a map of Oahu.

Hawaii has some of the fastest growing trees in the United States; climate conditions provide ideal growing conditions for particular species. For example, the Albizia species grew from 15-25 feet annually during the dry cycle whereas in 2005 and 2006, growth rates, as observed by HECO's arborists, have reached as much as 25-35ft per year. The significantly higher precipitation experienced in 2004-2006 has long term effects on vegetation growth because of water retention by the trees and other shrubs resulting from the resource of underground water that sustains larger vegetation. Besides the spurt in growth rates in vegetation because of the higher amounts of rainfall, there are more trees and shrubs and seeds from these trees promoted saplings in an around the existing vegetation. The increased abundance of rainfall and the fast growth rates resulted in a greater number of trees in the forested areas.

The heightened precipitation increased the volume of trees and foliage thereby necessitating greater coverage in the number of units that require trimming. In addition, the substantial growth in recent years demands a greater frequency of trimming to keep vegetation away from HECO's lines. HECO's vegetation management contractors adhere to best industry practices within the confines of environmental and aesthetic guidelines expected by the Oahu community.

In addition to increasing the frequency of the trimming cycles, HECO's tree trimming contractors have been temporarily shifted away from scheduled trimming cycles to respond to an increase in emergency tree-related outages and critical trimming requests mainly on the sub-transmission and distribution systems. Helicopter inspections to identify problem vegetation growth are increasing from once per quarter to twice per quarter. Extra contracted crews have been brought in from the mainland to address immediate trimming of vital transmission right-of-ways.

Q. Please describe the impact of the augmented vegetation management program to T&D O&M expenses.

A. HECO's Transmission Maintenance expense has increased by approximately $360,000 and Distribution Maintenance expense has increased by approximately $620,000 for a total of almost a $1 million increase in vegetation management spending for the 2007 Test Year and beyond. Exhibit HECO-730 outlines the factors contributing to HECO's 2007 and beyond vegetation management program increase. Vegetation Management program actual expenditures from 2000-2005, and budgeted 2006 vegetation management expenses, are outlined on HECO-731 and HECO-732.

3) <u>Wages and Non-labor Increases</u>

Q. What wage increases are included in the 2007 Test Year estimate?

A. The wage increases for bargaining unit employees are in accordance with the Company's negotiated labor agreement with the International Brotherhood of Electrical Workers, Local 1260. Wage increases for merit personnel occur annually in May with some wage adjustments occurring in September. As a result of the projected wage increases, on an annual basis, general wage rates for Test Year 2007 are expected to be 6.53% (for bargaining unit employees) and 7.64% (for merit employees) higher than the respective 2005 wage rates. Ms. Nanbu in HECO T-10 discusses the relative wage rates between 2005 and 2007 based on the wage increase assumptions for bargaining unit and merit employees discussed by Ms. Price in HECO T-12.

Q. What are the inflation estimates for non-labor expenses?

A. Non-labor expenses are estimated on the basis of quoted or contracted prices for materials and services. If these quoted or contracted prices were not available, the inflation increase was estimated to be 2.5% in 2007 as previously discussed.

4) T&D Plant Aging

Q. How are T&D O&M expenses affected by aging plant?

A. As the T&D facilities age, more emphasis must be placed on inspection and maintenance to identify and correct potential failures before they happen. These programs are needed to ensure customer service reliability.

Q. Please provide examples to show how HECO's plant is aging.

A. HECO-713 provides information on the increasing age of HECO's 138 kilovolt ("kV") overhead transmission circuits. The last major addition to the 138 kV overhead transmission system was in 1995 with the completion of the Waiau to Ewa Nui lines. As shown in HECO-713, the average age of the overhead lines increases each year, with a 2007 estimated average of 36.1 years. In addition, of the 213.6 overhead circuit miles, approximately 78% (167 miles) will be 30 years old or older.

HECO-714 provides information on the age of HECO's 138 kV underground transmission circuits. The system is relatively new with an estimated 2007 average

age of 12.7 years.

Q. How else has HECO's T&D plant aged?

A. HECO-715 provides information on the increasing age of HECO's 138 kV transmission transformers. As shown on HECO-715, the 2007 estimated average age of the 138 kV transmission transformers is 33.8 years. The 2007 estimated average age of 33.8 years is less than the 2005 average age of 34.3 years. The slight decrease in average age results from the replacement of two transmission transformers (Waiau 3 & Waiau 4) that were 57 and 54 years old respectively when the 2005 estimated average age was prepared in 2004. In addition, as shown on HECO-715, of the 46 transmission transformers, 74% (34) will be 30 years old or older in 2007.

HECO-716 provides information on the increasing age of HECO's distribution substation transformers. As shown, the average age of the distribution substation transformers is forecasted to be 31.4 years in 2007. In addition, of the 265 distribution transformers, 60% (159) are estimated to be 30 years or older in 2007.

Q. What is HECO doing to manage the expenses due to the aging facilities?

A. HECO will continue and is working toward expanding its existing inspection programs to identify problems and will continue its maintenance programs to correct the problems before they result in outages to customers. Using a spreadsheet that takes into account system risk and the condition of the equipment, maintenance items from the inspections can be prioritized so that HECO can manage its O&M expenses. But, as the system ages, more maintenance concerns are identified and deferred due to competing priorities. As the identified maintenance items continue to mount, this will result in more work in succeeding years as the deferral of identified work will one day need to be addressed to improve the situation or prevent an outage from occurring.

Q. What kind of work have the inspections uncovered that haven't been tended to immediately?

A. Some of inspection results that don't need to be addressed immediately are, painting of the steel structures in the substation, addressing corrosion on equipment or structures in the substation, corrosion on transformers both overhead and underground, or equipment that show signs of operating at slightly elevated temperatures that have not reached a critical point that would cause the equipment to fail are some examples of the work that is identified around the system.

Q. Is this an indication that HECO that the system is falling into disrepair?

A. No because, T&D O&M spending has increased over the years as HECO addressed equipment problems and attended to maintenance needs. Capital projects such as the Waikiki Rehabilitation Project was initiated by the company to address the issue of failing cables due to the degradation of the cables and the concentric neutrals. Over the years, there has been an increase in capital spending in plant replacement programs to replace these aging facilities. Two predominant areas where HECO has attributed outages due to aging assets have been in cables and wood pole failures. Through these capital replacement programs, HECO has been able to address cable outages and wood pole failures.

Q. In addition to the aging of HECO's distribution system, what other distribution system concerns exist?

A. There are other issues in addition to aging that impact the distribution system. The majority of the system interruptions causing outages to customers occur as a result of problems on the distribution system. Besides aging, other influences such as weather, pest infestation, vegetation, vehicle accidents, corrosion, and contamination affect the distribution system. With over 125 distribution substation and 2,200 miles of overhead and underground lines, a large resource pool is required to inspect and maintain the system. HECO is responding to this concern by increasing the amount of work in vegetation management as well as increasing inspections. Being more proactive in the management of vegetation will improve the reliability of the system and service to HECO's customers. Similarly, HECO's increased inspections of the distribution system (poles, overhead lines, and substations) can improve the reliability of the system and service to HECO's customers. Inspection findings identify repairs and replacements that need to be addressed before they result in an outage. The required maintenance activities identified through inspections will be prioritized and managed by HECO based on the available personnel and materials to support these maintenance activities. However, if the backlog of maintenance items is left to grow, then the probable impact is declining service reliability to HECO's customers.

5) Growth In T&D Utility Plant

Q. How has the T&D utility plant increased in recent years?

A. As shown on HECO-717, the amount of HECO's transmission utility plant is estimated to increase from $557,934,000 in 2005 to $595,068,000 in the 2007 Test Year estimate. This is an increase of $37,134,000. The distribution utility plant is estimated to increase from $1,059,331,000 in 2005 to $1,160,850,000 in 2007. This is an increase of $101,519,000.

Q. What factors contribute to the need for these increases to the T&D utility plant?

A. Increases to the T&D utility plant are the result of capital projects. These projects are initiated for a number of reasons:

- New customer service—new residential, commercial and industrial developments
- Customer Requests—line relocations, government improvement projects
- Increase in existing customer loads
- Reliability improvement projects
- Safety and system security

Q. What is the impact on T&D O&M expenses?

A. T&D plant additions represent new facilities that need to be operated, inspected, and maintained. The result is a need to increase staffing in the Construction and Maintenance, and System Operation Departments to address both capital and operation and maintenance requirements of the growing T&D plant.

<u>6) HECO System Reliability</u>

Q. How does HECO track overall T&D system reliability?

A. HECO utilizes several indices that are standard within the utility industry to measure overall reliability. The primary indicators include the following:

- System Average Interruption Frequency ("SAIF") as shown on HECO-718
- Customer Average Interruption Duration ("CAID") as shown on HECO-719
- System Average Interruption Duration ("SAID") as shown on HECO-720
- Average Service Availability ("ASA") as shown on HECO-721

See HECO-722 for an explanation of these indicators.

Q. Given the age of HECO's T&D system, how does HECO's reliability compare to past years' trends?

A. With the exception of HECO's SAIF performance in 2001 and 2003, over the past eight-year period, HECO's reliability has resulted in SAIF measurements ranging from 1.15 to 1.32. HECO's ASA has remained consistently at or above 99.98%.

Q. What were the circumstances that resulted in HECO's higher SAIF measurements reflecting a decrease in reliability for the years 2001 and 2003? (SAIF results of 1.76 and 1.65, respectively.)

A. In 2001 during the winter months, increases in the following outage cause categories - high winds, trees or branches, lightning and unknown failures - were the primary contributors to HECO's SAIF performance falling outside of HECO's normal range.

In 2003, an increase in outages due to equipment deterioration was the primary contributor to HECO's higher SAIF results. The equipment that failed and caused the outage was replaced so that power could be restored to HECO's customers. Included in this category of outages is deterioration of wood poles and this is being addressed through program initiatives for wood poles.

Greater attention has been placed on monitoring outages caused by equipment deterioration. Closer scrutiny has resulted in getting to the root cause of the outage and some of the outages that were initially attributed to equipment deterioration were actually the result of other causes. However, for those outages that have been attributed to equipment deterioration the equipment deterioration sub-committee of the Distribution Reliability Team has not identified that there is a systemic problem affecting only select pieces of equipment. What the equipment deterioration sub-committee has found is that equipment deterioration can affect many types of equipment so that it is difficult to narrow it down to one or two types of equipment that are the most susceptible. The sub-committee will continue to analyze the outages to determine a course of action in the future. At this time, we are conducting inspections and using infrared technology to identify equipment that potentially might fail if they are deteriorating.

Q. How has HECO been able to maintain reliability within a consistent range of SAIF during six of the past eight years?

A. HECO has been able to achieve high reliability results by making a commitment to reliability. This commitment to reliability can be measured by the expenditures that it has placed into its O&M expense budget. HECO-723 provides a graphical comparison of HECO's O&M expenditures and the number of outages that were experienced (reflected by the SAIF indicator).

This graph indicates the increased O&M expenditures over time have contributed to HECO's ability to reduce the number of outage occurrences. HECO intends to sustain this level of spending in the 2007 Test Year.

Reliability Initiatives

Q. Given the increasing scope and age of the system, what actions is HECO taking to continue to maintain or improve current levels of reliability?

A. To ensure this expenditure is applied most effectively, an analysis of the major causes of interruptions is regularly conducted. With this information, HECO can focus on addressing these causes to make further improvement on reliability.

Q. What are the major causes of interruptions?

A. While the major contributors differ each year, HECO-724 graphically summarizes the most typical outage causes in the past five-year period. Consistently topping the list are cable faults and equipment deterioration. Outages attributed to trees or branches in lines have increased to become the third highest cause of outages in 2005.

Q. With this information, what types of programs and initiatives has HECO implemented?

A. In addition to regular and routine maintenance efforts, HECO implemented several programs and initiatives to improve reliability in the following standard HECO categories:

1) Cable Faults - Projects that have been implemented or initiated include the direct burial cable replacement projects and programs, the Waikiki Rehabilitation Project, and implementation of single phase transformers with loop feed protection. Because they are not immediately visible, underground cable faults are challenging to locate and repair; leading to lengthy repair efforts and increased costs. Typically, a cable fault is indicative of an aging, defective cable run as additional, separate faults usually occur within a close period of time. These programs will focus HECO efforts on replacing entire runs of cable rather than patching, or repairing portions of the cable. The capital dollars to replace the cables would at first appear to be more costly than making repairs. However, one reason why the cables are failing is the corrosion and deterioration that occurs when the cable is in contact with the surrounding soil. The capital expenditures in the cable replacement program provide for the installation of underground ductlines in which the new cables will be installed. Ductlines protect the cable from contact with the soil that can deteriorate the insulation as well as facilitates. Ductlines provide for easier removal of cable in the future, in case there is a need to replace the cable. Replacing the cable under this program is an effective way to improve the reliability of service to the customer.

HECO has also increased underground inspections. Cable faults are HECO's number one outage cause. HECO has adopted Very Low Frequency ("VLF") cable testers to troubleshoot and detect cable problems. VLF technology yields more precise results than traditional methods with considerably less risk to the circuit. VLF testing has identified cable faults that other methods have missed. While VLF technology is superior to traditional DC Hi-pot testing, use of this technology does take more time to test the cable and thereby increases associated O&M labor costs.

2) Equipment Deterioration – HECO's T&D Maintenance Optimization Program helps the Company better prioritize, plan and schedule work. Central to this program is the regular use of technology such as Infrared and Corona testing helicopter inspections, high-resolution digital camera inspections, and the use of a Distribution Inspection Data System ("DIDS") that maintains inspection data and assists in the prioritization of work.

3) Trees/Branches – Customer outages attributed to trees/branches (in distribution lines) reached a 6-year high in 2005 and was the third highest cause of outages in 2005, as shown in HECO-724. HECO has increased the frequency and volume of tree trimming in response to increased outages due to vegetation growth as a result of higher rainfalls. I previously discussed in my testimony expense increases to HECO's transmission and distribution maintenance / vegetation management program

4) Faulty Equipment - HECO has adopted the concept of Asset Management. This strategic approach to reliability identifies system, circuit and equipment owners who can focus on their specific part of the system and put the necessary care in ensuring that their responsible areas are able to deliver reliable service. Additionally, the use of technology in various parts of the system helps to provide early indication of potential problems and automatic or remote switching capability. This includes automated substation relays,

automated switches and automated transformers.

Q. What additional work is being done to HECO's distribution facilities?

A. HECO has increased the amount of inspections of the distribution facilities to improve reliability. By performing these inspections, HECO can identify and resolve problems on the distribution system before an outage occurs. This may also lower the number of "unknown" outages as time and effort can be expended to find problems on the system in a planned condition rather than trying to find the cause of a problem when HECO is attempting to restore power to the affected customers as quickly as possible.

HECO is increasing test and treat programs for wood poles to reduce capital spending associated with installation of new poles. Treating wood poles has proven to be a cost-effective method that extends the life of wood poles. Increased expenses for test and treat programs account for $149,000 of the increase to Distribution Maintenance expense in 2007.

Q. Are there any other reliability initiatives planned for the future?

A. Yes. Another major initiative is the Outage Management System ("OMS"), which HECO plans to implement in 2007, as referenced earlier in my "New System Operation Technology" testimony.

7) Staffing Increases

Q. What are the estimated staffing levels in 2007?

A. HECO-725 shows the 2007 Test Year estimated staffing levels in the Construction & Maintenance, Support Services, Engineering, and System Operation Departments and includes prior staffing levels from 2004-2006 for these same Departments.

Q. How do the 2007 Test Year estimated staffing levels compare to the 2005 EOY recorded staffing levels and 2006 projected EOY staffing levels as shown in HECO-725?

A. The total 2007 estimated staffing level for the represented areas is 509 compared to a 2005 recorded EOY staffing level of 495, or a 2.8% increase over 2005. The estimated 2006 EOY staffing level has decreased to 490 due to unfilled vacancies currently under recruitment. HECO expects to attain the 2007 Test Year estimating staffing level of 509 by mid-year 2007.

Q. With the previously reported efficiency improvements that HECO has done over the years, why is it necessary to increase the size of the workforce?

A. Although many efficiency programs have been implemented, all the work that has to be done on every aspect of the electrical system requires skilled physical labor. For example, highly knowledgeable and skilled employees are needed to place a pole, outfit it with the necessary equipment and install the power lines and transformers as required. In the substations when a transformer or circuit breaker needs repair, skilled technicians use test equipment to identify the problem and perform the physical work to make the appropriate repairs. These are just two examples of why additional staffing is necessary. As indicated earlier, the electrical system is aging as well as growing and the workforce must be sized to perform the work albeit on a prioritized basis. Notwithstanding the concerted effort to prioritize the work, unplanned outages, or emergency repairs happen and HECO needs a sufficient number of employees to support both planned and unplanned work.

Q. Please explain the 2006 projected EOY vacancies (2) in the Construction and Maintenance Department and when these vacancies are expected to be filled.

A. The Construction and Maintenance Department 2007 Test Year staffing level estimate is 220. This represents an increase of 2 employees from the projected 2006 EOY count of 218. The Department recently hired 14 new Senior Helpers. Two other candidates have been identified and will start as Senior Helpers on January 22, 2007, bringing the C&M staffing level to the 2007 Test Year estimate of 220. Senior Helpers are indentured into an apprenticeship program conducted by HECO. While in this program, they will spend 3 to 4 years learning the skills of a lineman. This training is especially critical to ensure that the work is performed correctly and safely because of the extremely high voltages that are used by HECO and because the work is physically demanding. After graduating from the apprenticeship program, another 3 to 5 years are spent refining these skills and developing the job knowledge and confidence to tackle the work that they are faced with. A five-year period is required to develop the knowledge and skills necessary to become a journey line worker. HECO must have enough staffing to meet the work demands while providing critical training and development opportunities to employees. The addition of Senior Helpers into the apprenticeship program strengthens the future pool of skilled, experienced employees to offset future attrition in the Construction and Maintenance Department.

Q. Please explain the 2006 projected EOY vacancy (1) in the Engineering Department and when the vacancy is expected to be filled.

A. The Engineering Department 2007 Test Year staffing level estimate is 85. This represents an increase of 1 employee from the projected 2006 EOY count of 84. The Engineering Department has successfully recruited to fill a Telecom Engineer position, vacated in November, 2006 when the incumbent employee transferred to HECO's Power Supply Engineering Department. The Telecom Engineer candidate is expected to start employment with HECO in January, 2007.

Q. Please explain the 2006 projected EOY vacancies (4) in the Support Services Department and when these vacancies are expected to be filled.

A. The Support Services Department 2007 Test Year staffing level estimate is 85. This represents an increase of 4 employees from the projected 2006 EOY count of 81. All 4 vacancies are expected to be filled in 1Q 2007.

a) A Contract Administrator vacancy occurred in December, 2006 due to an internal promotion to the Senior Contract Administrator position. This vacancy is expected to be filled in January, 2007.

b) A Service Station Attendant vacancy occurred in 3Q 2006 upon the incumbent employee's transfer to the Power Supply Operations & Maintenance Department. A candidate has been identified and is expected to start employment with HECO in January, 2007.

c) Two (2) Mechanic vacancies occurred in 4Q 2006 upon the incumbent employees' transfers to the Power Supply Operations & Maintenance Department. Support Services is actively recruiting for these positions and expects to fill the 2 vacancies in 1Q 2007.

Q. Please explain the System Operation Department differences in the 2007 Test Year estimated staffing level, the 2006 projected EOY staffing level, and the recorded 2005 EOY staffing level, as shown on HECO-725.

A. The System Operation Department 2007 Test Year staffing level estimate is 117. The 2006 projected EOY staffing level of 105 represents 12 vacancies that, when filled, will result in attaining the 2007 Test Year estimate of 117. The 2006 projected EOY staffing level of 105 has decreased from the recorded 2005 EOY staffing level of 112. The System Operation Department has experienced significant attrition over the last several years resulting in a loss of technical knowledge and experience. The Department has worked diligently to find candidates that can immediately fill a position, but it has been difficult to find candidates with prior utility experience.

Q. Please describe why recruiting candidates for the positions in the System Operation Department is challenging.

A. The System Operation Department positions vacant in the Substation and Dispatch areas require highly skilled employees with knowledge gained from direct utility experience. Unless a candidate is recruited from another utility, HECO must rely on employees trained in-house. The C&M Department's apprenticeship program prepares employees who sometimes choose to transfer to the System Operation Department to work as Substation Electricians. In this case, although they are graduates of the apprenticeship program, they will spend another 3,000 hours learning the skills of substation work. After completing the 3,000 hours of training, they will need another 3 to 5 years to hone their skills. Another area that requires highly skilled employees is the System Operation Department's dispatch office where the employees have responsibility to monitor and control the entire HECO system. Again, the trained C&M Department employees sometimes choose to work in System Operation as Trouble Dispatchers, a position that feeds into the Load Dispatcher position, as it is a line of progression promotion. With such a huge investment in preparing people for these positions it is important that those people trained be retained through full employment by HECO rather than using temporary contracted resources.

Q. Why must the 2007 Test Year estimate staffing levels of 117 be attained in the System Operation Department when the Department has operated over the last several years with a lower staffing level, primarily due to unfilled vacancies?

A. The increased staffing is to address increased system requirements as a result of the continuing growth and age of the utility plant, as previously discussed, to account for the loss of technical knowledge and experience through retirements of existing staff, and to support the new EMS and OMS systems. Replacement employees do not have similar levels of knowledge and experience as retiring employees and as a result, this causes somewhat lower productivity levels and increases training requirements. Adequately staffing the System Operation Department is critical because of the responsibilities the staff has for maintaining and operating the electrical system. Additionally, one position was filled in response to the work demand for the new Outage Management System. In HECO's response to CA-IR-15, in Decision and Order No. 21899 issued on June 30, 2005 in Docket. 04-0131, HECO indicated that the existing staff would be used to support the new OMS and that HECO would be filling existing positions that were vacant in the System Operation Department to support the EMS and OMS. However, during the initial implementation phase of the OMS it was determined that an additional resource was required to support the OMS project. This need is based on the current workload and in anticipation of the support required for the new OMS. The additional employee as well as the existing employees in the System Operation Department will be cross trained on the technical skills required to support both the Siemens EMS and the SPL Worldgroup OMS. However, the additional workload that has been required to set up the computer environment, to support the business application, to work with all the interfaces to other systems, e.g., EMS and ACCESS (HECO's customer information system) and other systems was greater than what the existing staff could manage in addition to their responsibilities for the EMS.

Q. Please explain the 2006 projected EOY vacancies (12) in the System Operation Department and when these vacancies are expected to be filled.

A. These are the current vacancies in the System Operation Department:

a. Technical Trainer, currently conducting interviews. Expect to fill in January, 2007.
b. Director of Special Projects, expected to transfer into System Operation Department in January, 2007.
c. Two (2) EFMS Technicians. Expect to fill by mid 2007.
d. Substation Electrician. Expect to fill in first quarter 2007.
e. System Coordinator. Currently vacant, position to be filled in first quarter 2007.
f. 2nd Switching Coordinator. Expect to fill in January, 2007. Note the incumbent currently in the position is retiring in the 4Q 2006.
g. Reliability Analyst, vacated in 4Q 2006. Work is currently underway to fill this position.
h. Two (2) Trouble Dispatchers. Expect to fill by early to mid - 2007.
i. PDM Specialist. Will be joining HECO December 18, 2006.
j. Mapping Division Supervisor. Expect to fill by mid-2007.

Q. Is it difficult to find people with the appropriate skill sets for positions in System Operation Department?

A. We have found that the job market for certain positions, e.g., the Mapping Supervisor, EFMS Technicians is a difficult market. We have had applicants for these positions, however, in the case of the EFMS Technicians, few have been able to pass HECO's entrance exams. The Mapping Supervisor position has attracted applicants to HECO but in the applicants lacked the skills necessary for the job.

These areas as well as the dispatcher position, requires careful screening because people in these positions and the result of their work could have a significant negative impact on the electrical system if they make errors on the job. As a result, HECO will hire applicants that successfully pass the screening process and the employment interview.

2006 TRANSMISSION and DISTRIBUTION O&M EXPENSES

Q. How does the T&D O&M 2006 year end estimate, as of November, 2006, compare to the 2006 operating budget?

A. By 2006 year end, HECO estimates actual T&D O&M expenses to total $31,259,000. This amount is $1,389,000 less than the 2006 operating budget of $32,648,000 as shown in HECO-733. The 2006 estimate is the sum of actual year-to-date spending as of November 30, 2006 and estimated spending for December, 2006.

Q. Please explain why HECO estimates to end the year 2006 with a ($1,389,000) variance from the 2006 operating budget?

A. As explained earlier in my testimony, there were a number of unfilled vacancies in the System Operation department, many of those occurring unexpectedly as employees retired or transferred to other departments in HECO. Finally, some of the variance is due to work done to support the capital projects; such as Ocean Pointe Substation and the remaining work for the EMS / New Dispatch Center as well as other projects. While the System Operation crews were working on these projects, maintenance items were postponed. Upon completion of the capital projects work in System Operation was re-directed back to the planned maintenance work.

Q. How was HECO able to manage with lower staffing levels?

A. Managing the work required significant review and prioritization to assign critical work to limited available resources. In most cases this work was focused on the equipment that, if not addressed, could have a large impact on the system in terms of causing widespread outages. In other cases, work was prioritized to address poor reliability affecting particular areas on the system.

T&D MATERIALS INVENTORY

Q. What is the estimated Test Year 2007 T&D materials inventory?

A. The average T&D materials inventory is estimated to be $6,636,037 as shown on HECO-703.

Q. What is included in the T&D materials inventory?

A. The T&D materials inventory includes those items required in the day-to-day construction, operation and maintenance of the T&D system. It does not include distribution transformers, substation transformers or major substation equipment.

Q. How many warehouses does HECO operate to store and distribute the T&D materials inventory?

A. HECO operates three materials warehouses which are located at the following base yards:

1) Ward Avenue,
2) Waiau
3) Koolau

Q. Why is the test year 2007 T&D materials inventory reasonable?

A. Estimates for the 2007 test year T&D materials inventory were derived by taking the estimated 2006 year-end values and projecting 2007 inventory to include increased values attributed to higher material replacement costs. This informed forecast was aided by utilizing monthly recorded figures that portray inventory levels and movement. Some of the information contained in these reports is year-end inventory values, average values and total issues as shown on HECO-703.

Q. How does the 2007 test year T&D materials inventory compare with levels recorded in preceding years?

A. The average T&D materials inventory for 2007 test year increases $566,781 or 9% from the average T&D materials for recorded 2005 as shown on HECO-703.

Q. Please explain the factors attributed to the 2007 estimated materials inventory increase of $566,781 over recorded 2005.

A. In 2006, safety stock of key materials was increased to ensure reliability. Included are inventory additions of concrete, steel, fiberglass, and "H" (higher class of wind-resistance, wood) poles. A sampling of replacement materials ordered in 2006 indicates an approximate 17% increase in material costs over previous inventoried values.

Q. Why are 17% increases to materials reasonable?

A. Global market conditions for metals and fuels have driven dramatic increases in prices of steel, copper, aluminum, and resins along with increases to transportation/freight. Market price increases for some of these commodities are shown on HECO-726. Much of the T&D inventoried materials are manufactured with metals and resins. The sharp increases to these raw materials have resulted in much higher manufacturer's costs that are passed on to HECO in increased materials contract or purchase prices.

SUMMARY

Q. Mr. Young, please summarize your testimony.

A. HECO's test year T&D O&M expense is estimated to be $35,213,000 for 2007 test year, as shown in HECO-701, with a breakdown of $10,491,000 for transmission and $24,722,000 for distribution as shown in HECO-702.

HECO's goal is to deliver reliable, cost-effective service to its customers. The costs associated with this goal have been highlighted in this testimony.

HECO is strategically managing expenses to ensure that reliable service can be sustained. HECO's 2007 test year T&D O&M expense estimate of $35,213,000 is 17% higher than actual 2005 T&D O&M expenses, as adjusted as shown in HECO-707. This increased level of expenses is critical, given the increasing scope and age of the T&D system; pending retirements and the resulting experience drain; increased vegetation management to secure transmission system reliability; and support of the new System Operation technologies.

The T&D materials inventory is forecasted to be an average of $6,636,037 as shown in HECO-703. Rising material costs are a primary contributor to the increase in average inventory value.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

ROBERT K. S. YOUNG

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 820 Ward Avenue, Honolulu, HI 96814
POSITION:	Manager, System Operation Department. Hawaiian Electric Company, Inc. (April 2005 to present)
YEARS OF SERVICE:	28 Years
EDUCATION:	University of Hawaii
DEGREE:	Bachelor of Science, Electrical Engineering Masters, Business Administration
PREVIOUS POSITIONS:	Manager, New Dispatch Center Project Hawaiian Electric Company, Inc. (December 2002 to March 2005) Manager, System Operation Department Hawaiian Electric Company, Inc. (February 1999 to November 2002) Senior Engineer, System Operation Department Hawaiian Electric Company, Inc. (October 1991 to January 1999) Electrical Engineer, System Operation Department Hawaiian Electric Company, Inc. (November 1988 to September 1991) Electrical Engineer, System Planning Hawaiian Electric Company, Inc. (May 1978 to October 1988)
OTHER QUALIFICATIONS:	Licensed Professional Engineer, Electrical State of Hawaii 1983

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION & MAINTENANCE EXPENSE
($ Thousands)

	2007 TEST YEAR
TOTAL T&D O&M EXPENSE	35,213

Source:
HECO-702

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION AND DISTRIBUTION MATERIAL INVENTORY

		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2005 vs 2007	
		(A) 2001	(B) 2002	(C) 2003	(D) 2004	(E) 2005	(F) 2006	(G) 2007	(H=G-E) $	(I =H/E) %
1	Year-End Value	$4,409,160	$ 4,716,184	$ 5,728,651	$ 5,172,560	$ 6,645,048	$ 6,332,689	$ 6,939,385	294,337	4
2	Average Value	$4,560,514	$ 4,573,592	$ 5,134,358	$ 5,203,504	$ 6,069,256	$ 6,537,350	$ 6,636,037	566,781	9
3	Total Issues	$5,921,076	$ 6,065,816	$ 6,584,028	$ 7,838,220	$ 6,582,250	$ 7,803,644	$ 8,303,968	1,721,718	26

notes:

1 2004 & 2005 updated to actuals

2 2006 forecast/estimate extrapolated based on 8 mths actuals, scheduled activities and historical trends
Increases in inventory value in 2006 due to the following:

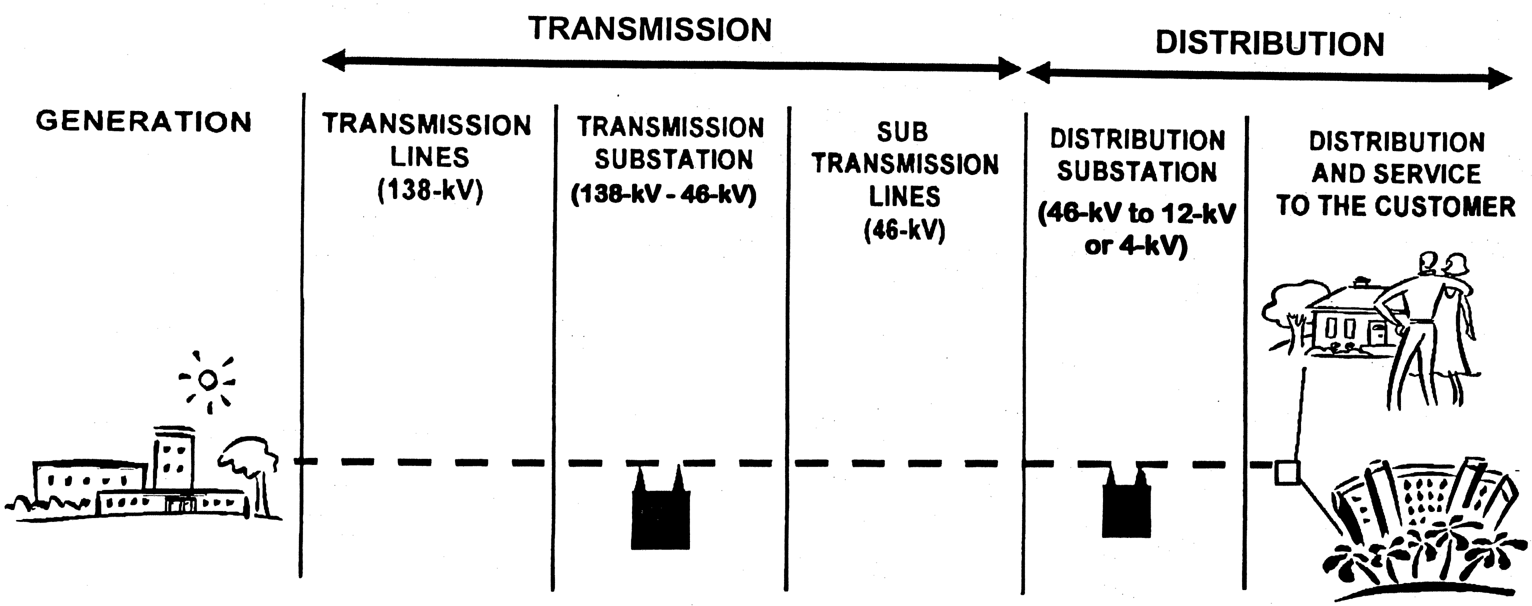
a. Average price increase based on sample of 100 items = +17%
b. New types of poles added to inventory (concrete, steel, fiberglass, H poles) = +$250,000
c. Increase in Whse min/max to minimize stockouts = + $560,000
d. Estimated increase in usage/issues from 2005 = +$1,221,394

3 2007 (Test Year Estimate) based on preliminary capital budget + the following:

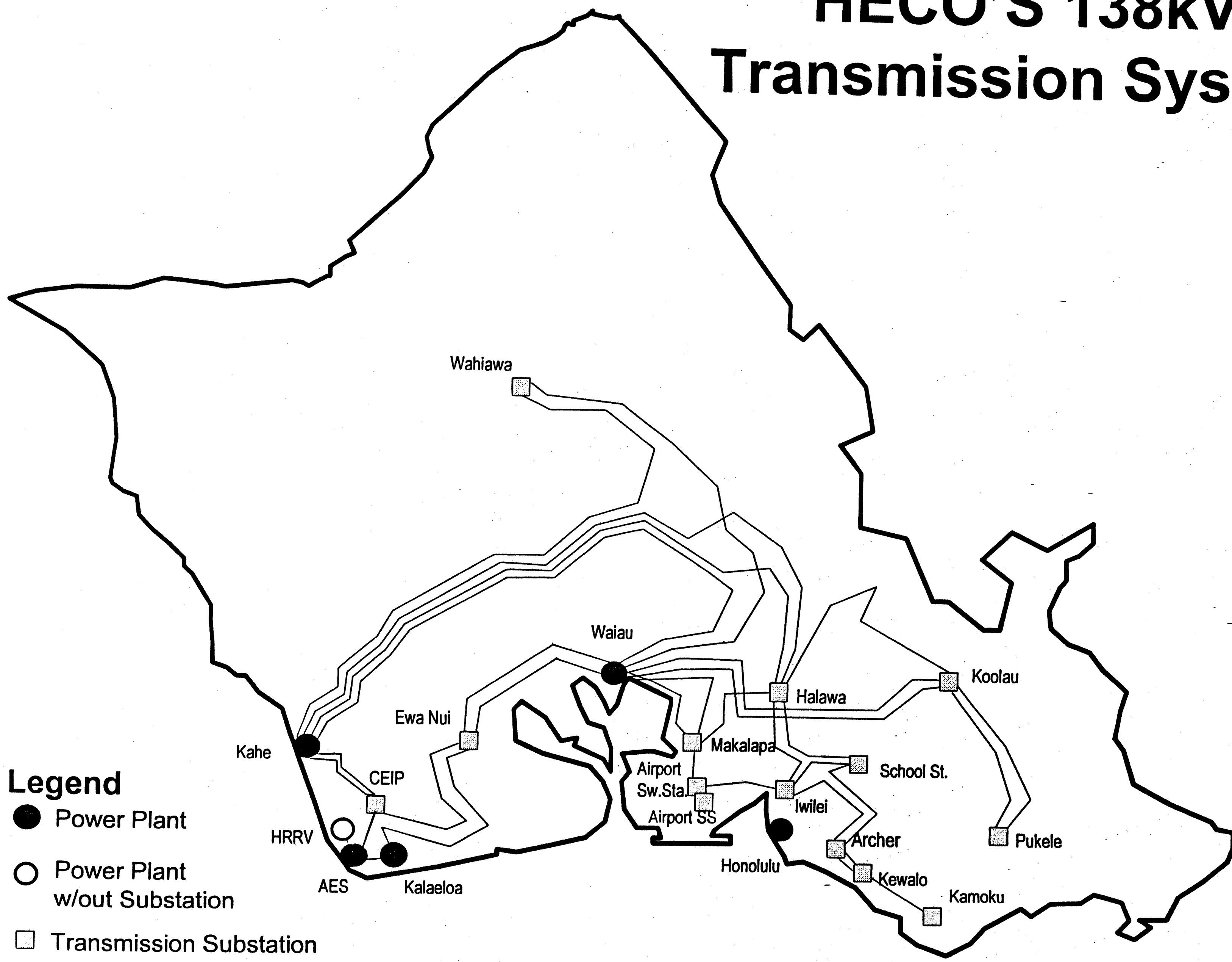
a. New poles added to inventory + increased safety stock = + $310,000
b. Increase replacement cost + 15-20%
c. Increase in usage/issues from 2006 = +$500,324

Note:
Figures may not total exactly due to rounding.

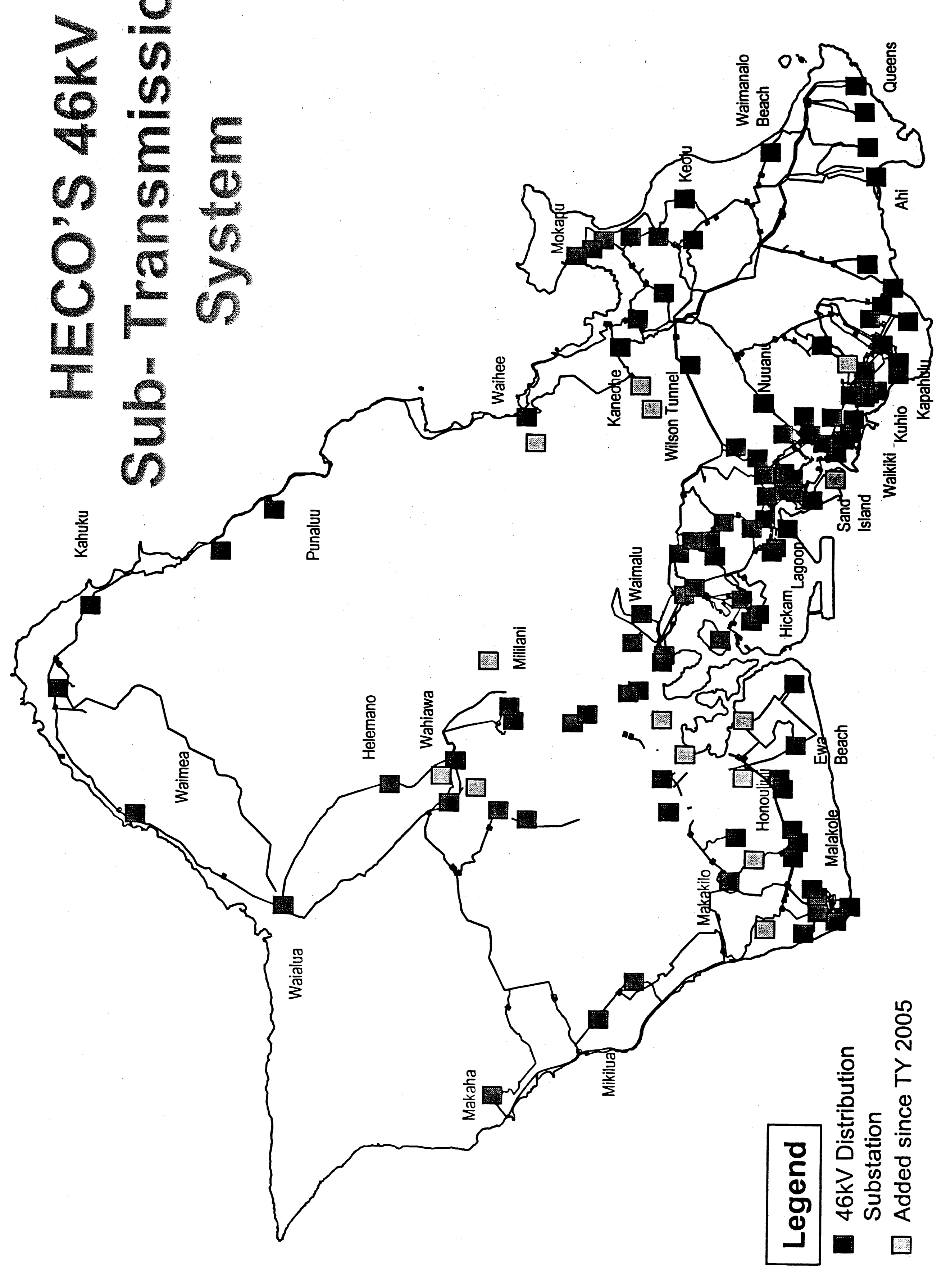
HECO's Power Delivery System



HECO'S 138kV Transmission System



HECO-706
DOCKET NO. 2006-0386
PAGE 1 OF 1



Hawaiian Electric Company, Inc.
2007 Test Year

TRANSMISSION & DISTRIBUTION O&M EXPENSE
($ Thousands)

		RECORDED					FORECAST	TEST YEAR ESTIMATE	2005 vs 2007	
		(A)	(B)	(C)	(D)	(E) Adjusted	(F)	(G)	(H=G-E)	(I=H/E)
		2001	2002	2003	2004	2005	2006	2007	$	%
1	Transmission O&M	$6,885	$6,699	$6,989	$8,107	$7,684	$9,553	$10,491	$2,807	37
2	Distribution O&M	$20,484	$19,626	$17,219	$21,002	$20,159	$23,094	$24,722	$4,563	23
3	Subtotal	$27,369	$26,324	$24,208	$29,108	$27,843	$32,647	$35,213	$7,370	26
4	*Adjustments	$333	$427	$981	$890	-	-	-	-	-
5	Adjusted Total	$27,702	$26,751	$25,189	$29,998	$27,843	$32,647	$35,213	$7,370	26
6	Increase / (Decrease)		-3%	-6%	19%	-7%	17%	8%		

HECO-707
DOCKET NO. 2006-0386
PAGE 1 OF 1

Source:
HECO-WP-101(A), page 3 and 4 for Columns (A-D) and (F).
HECO-734 for Column (E)
HECO-702 for lines 1 and 2, Column F.
HECO-727 line 15 for Columns (A-D) line 4 adjustments.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION O&M EXPENSE
($ Thousands)

	Transmission Expense	2007 TEST YEAR ESTIMATE
1	Operations	$ 5,378
2	Maintenance	$ 5,113
3	Total	$ 10,491

Source:
HECO-709

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A) OPERATING BUDGET	(B) BUDGET RATEMAKING ADJUSTMENTS	(C) NORMAL-IZATION	(D) 2007 TEST YEAR ESTIMATE
	Transmission Operation				
1	Labor	$ 2,535	-	-	$ 2,535
2	Non-Labor	$ 2,880	(37)	-	$ 2,843
3	TOTAL	$ 5,415	(37)	-	$ 5,378
	Transmission Maintenance				
4	Labor	$ 1,934	-	-	$ 1,934
5	Non-Labor	$ 3,158	21	-	$ 3,179
6	TOTAL	$ 5,092	21	-	$ 5,113
7=3+6	TOTAL TRANS O&M	$ 10,507	(16)	-	$ 10,491
	Distribution Operation				
8	Labor	$ 5,325	(68)	-	$ 5,257
9	Non-Labor	$ 5,394	10	-	$ 5,404
10	TOTAL	$ 10,719	(58)	-	$ 10,661
	Distribution Maintenance				
11	Labor	$ 5,427	-	-	$ 5,427
12	Non-Labor	$ 8,622	12	-	$ 8,634
13	TOTAL	$ 14,049	12	-	$ 14,061
14=10+13	TOTAL DIST O&M	$ 24,768	(46)	-	$ 24,722
15=7+14	GRAND TOTAL O&M	$ 35,275	$ (62)	$ -	$ 35,213

Source:
HECO-WP-101(A), page 3 for lines 1 to 6, Column A.
HECO-WP-101(A), page 4 for lines 8 to 13, Column A.
HECO-WP-710 for Column B
Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION O&M EXPENSE
($ Thousands)

		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2005 vs 2007	
		(A)	(B)	(C)	(D)	(E) Adjusted	(F)	(G)	(H=G-E)	(I=H/E)
		2001	2002	2003	2004	2005	2006	2007	$	%
1	Operation	$3,421	$2,809	$3,275	$3,532	$3,971	$5,078	$5,378	$ 1,407	35
2	Maintenance	$3,464	$3,890	$3,714	$4,574	$3,713	$4,475	$5,113	$ 1,400	38
3	Subtotal	$6,885	$6,699	$6,989	$8,107	$7,684	$9,553	$10,491	$ 2,807	37
4	*Adjustments	$15	$10	$64	($8)	-	-	-	-	-
5	Adjusted Total	$6,900	$6,709	$7,053	$8,099	$7,684	$9,553	$10,491	$ 2,807	37
6	Increase / (Decrease)		-3%	5%	15%	-5%	24%	10%		

Source:
HECO-WP-101(A), pages 3 and 4 for Columns (A-D) and (F).
HECO-734 for Column (E).
HECO-708 for lines 1 to 3, Column G.
HECO-727 line 7 for Column (A-D) line 4 *adjustments.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

DISTRIBUTION O&M EXPENSE
($ Thousands)

	Distribution Expense	2007 TEST YEAR ESTIMATE
1	Operation	$ 10,661
2	Maintenance	$ 14,061
3	Total	$ 24,722

Source:
HECO-709

Hawaiian Electric Company, Inc.
2007 TEST YEAR
DISTRIBUTION O&M EXPENSE
($ Thousands)

		RECORDED					OPERATING BUDGET	TEST YEAR ESTIMATE	2005 vs 2007	
		(A)	(B)	(C)	(D)	(E) Adjusted	(F)	(G)	(H=G-E)	(I=H/E)
		2001	2002	2003	2004	2005	2006	2007	$	%
1	Operation	$8,049	$7,669	$7,802	$8,404	$8,804	$9,813	$ 10,661	$1,857	21
2	Maintenance	$12,435	$11,957	$9,417	$12,597	$11,355	$13,281	$ 14,061	$2,706	24
3	Total	$20,484	$19,626	$17,219	$21,002	$20,159	$23,094	$ 24,722	$4,563	23
4	*Adjustments	$318	$417	$917	$898	-	-	-	-	-
5	Adjusted Total	$20,802	$20,043	$18,136	$21,900	$20,159	$23,094	$ 24,722	$4,563	23
6	Increase / (Decrease)		-4%	-10%	21%	-8%	15%	7%		

Source:
HECO-WP-101(A), pages 3 and 4 for Columns (A to D) and (F).
HECO-734 for Column (E)
HECO-711 for lines 1 to 3, Column G.
HECO-727 line 14 for Column (A-D) line 4 *adjustments.

Hawaiian Electric Company, Inc.
2007 Test Year

AGING OF 138kV OVERHEAD TRANSMISSION LINES

	(A) Year	(B) Line-Age in Service (Mile-Years)	(C) Miles in Service (Miles)	(D) Average Age (Years)
1	2000 (recorded)	6209.2	213.6	29.1
2	2001 (recorded)	6422.8	213.6	30.1
3	2002 (recorded)	6636.4	213.6	31.1
4	2003 (recorded)	6850.0	213.6	32.1
5	2004 (recorded)	7063.6	213.6	33.1
6	2005 (recorded)	7277.2	213.6	34.1
7	2006 (forecast)	7490.8	213.6	35.5
8	2007 (forecast)	7704.4	213.6	36.1

138 kV OH Transmission Line Age (2007 Forecasted)

(A) Years	(B) Miles	(C) % of Total
30+ Years	167.0	78.2%
25+ Years	0.0	0.0%
20+ Years	7.0	3.3%
15+ Years	10.3	4.8%
10+ Years	29.3	13.7%
5+ Years	0.0	0.0%
0+ Years	0.0	0.0%

Source:
HECO-WP-706

Hawaiian Electric Company, Inc.
2007 Test Year

AGING OF 138kV UNDERGROUND TRANSMISSION LINES

	(A) Year	(B) Line-Age in Service (Mile-Years)	(C) Miles in Service (Miles)	(D) Average Age (Years)
1	2000 (recorded)	51.3	5.7	8.9
2	2001 (recorded)	57.1	6.4	8.9
3	2002 (recorded)	63.5	8.3	8.7
4	2003 (recorded)	71.8	8.3	8.7
5	2004 (recorded)	80.0	8.3	10.7
6	2005 (recorded)	88.3	8.3	11.7
7	2006 (forecast)	96.6	8.3	11.7
8	2007 (forecast)	104.9	8.3	12.7

138 kV UG Transmission Line Age (2007 Forecasted)

(A) Years	(B) Miles	(C) % of Total
30+ Years	0.0	0.0%
25+ Years	0.0	0.0%
20+ Years	0.0	0.0%
15+ Years	4.5	48.3%
10+ Years	0.5	11.6%
5+ Years	3.2	1.4%
0+ Years	0.0	0.0%

Source:
HECO-WP-707

Hawaiian Electric Company, Inc.
2007 Test Year

AGING OF 138kV TRANSMISSION TRANSFORMERS

	(A) Year	(B) Number in Service	(C) Total Age (Years)	(D) Avg Age (Years)
1	2000 (recorded)	46	1377	29.9
2	2001 (recorded)	46	1423	30.9
3	2002 (recorded)	46	1469	31.9
4	2003 (recorded)	46	1485	32.3
5	2004 (recorded)	46	1474	32.0
6	2005 (recorded)	46	1465	31.8
7	2006 (forecast)	46	1511	32.8
8	2007 (forecast)	46	1557	33.8

138 kV Transformer Age (2007 Forecasted)

(A) Years	(B) Number of Transformers	(C) % of Total
30+ Years	34	74%
25+ Years	1	2%
20+ Years	0	0%
15+ Years	2	4%
10+ Years	5	11%
5+ Years	2	4%
0+ Years	2	4%

Source:
HECO-WP-708

Hawaiian Electric Company, Inc.
2007 Test Year

AGING OF DISTRIBUTION SUBSTATION TRANSFORMERS

	(A) Year	(B) Number in Service	(C) Total Age (Years)	(D) Avg Age (Years)
1	2000 (recorded)	251	6878	27.4
2	2001 (recorded)	253	7059	27.9
3	2002 (recorded)	254	7312	28.8
4	2003 (recorded)	257	7445	29.0
5	2004 (recorded)	258	7573	29.4
6	2005 (recorded)	265	7783	29.4
7	2006 (forecast)	265	8048	30.4
8	2007 (forecast)	265	8313	31.4

Distribution Substation Transformer Age (2007 Forecasted)

	(A) Years	(B) Number of Transformers	(C) % of Total
7	30+ Years	159	60%
8	25+ Years	7	3%
9	20+ Years	6	2%
10	15+ Years	18	7%
11	10+ Years	34	13%
12	5+ Years	16	6%
13	0+ Years	25	9%

Source:
HECO-WP-708

Hawaiian Electric Company, Inc.
2007 Test Year

TRANSMISSION AND DISTRIBUTION UTILITY PLANT
YEAR-END TOTALS
($ Thousands)

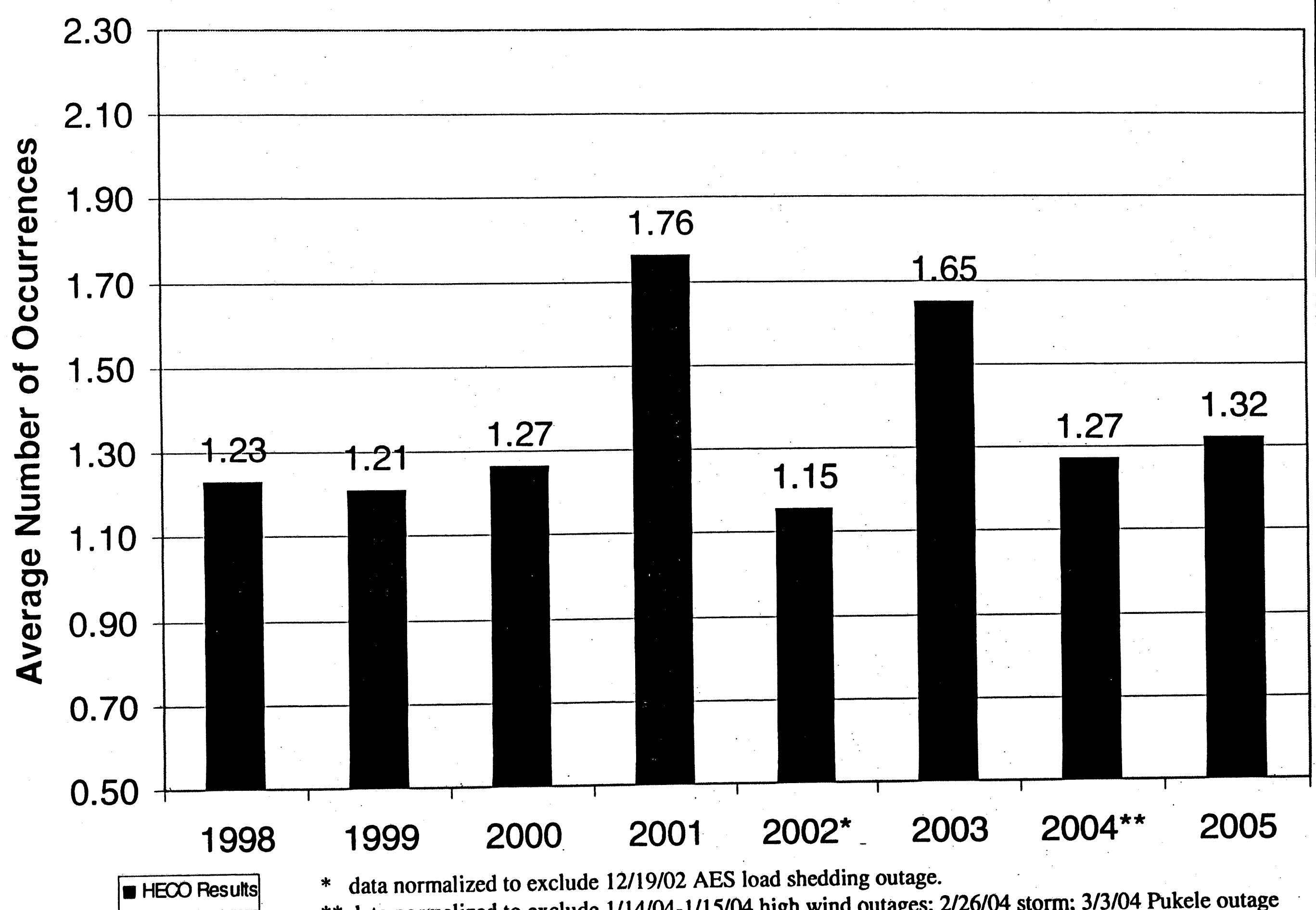
	(A)	(B) Transmission	(C) Distribution	(D) Total	(E) Annual Increase
1	2007 (estimated)	595,068	1,160,850	1,755,918	56,640
2	2006 (estimated)	585,382	1,113,896	1,699,278	82,013
3	2005 (recorded)	557,934	1,059,331	1,617,265	65,352
4	2004 (recorded)	546,710	1,005,203	1,551,913	63,512
5	2003 (recorded)	533,656	954,745	1,488,401	38,559
6	2002 (recorded)	529,101	920,741	1,449,842	56,970
7	2001 (recorded)	504,623	888,249	1,392,872	67,069

Transmission and distribution utility plant includes land and land rights

Source:
HECO-WP-710

Note:
Figures may not total exactly due to rounding.

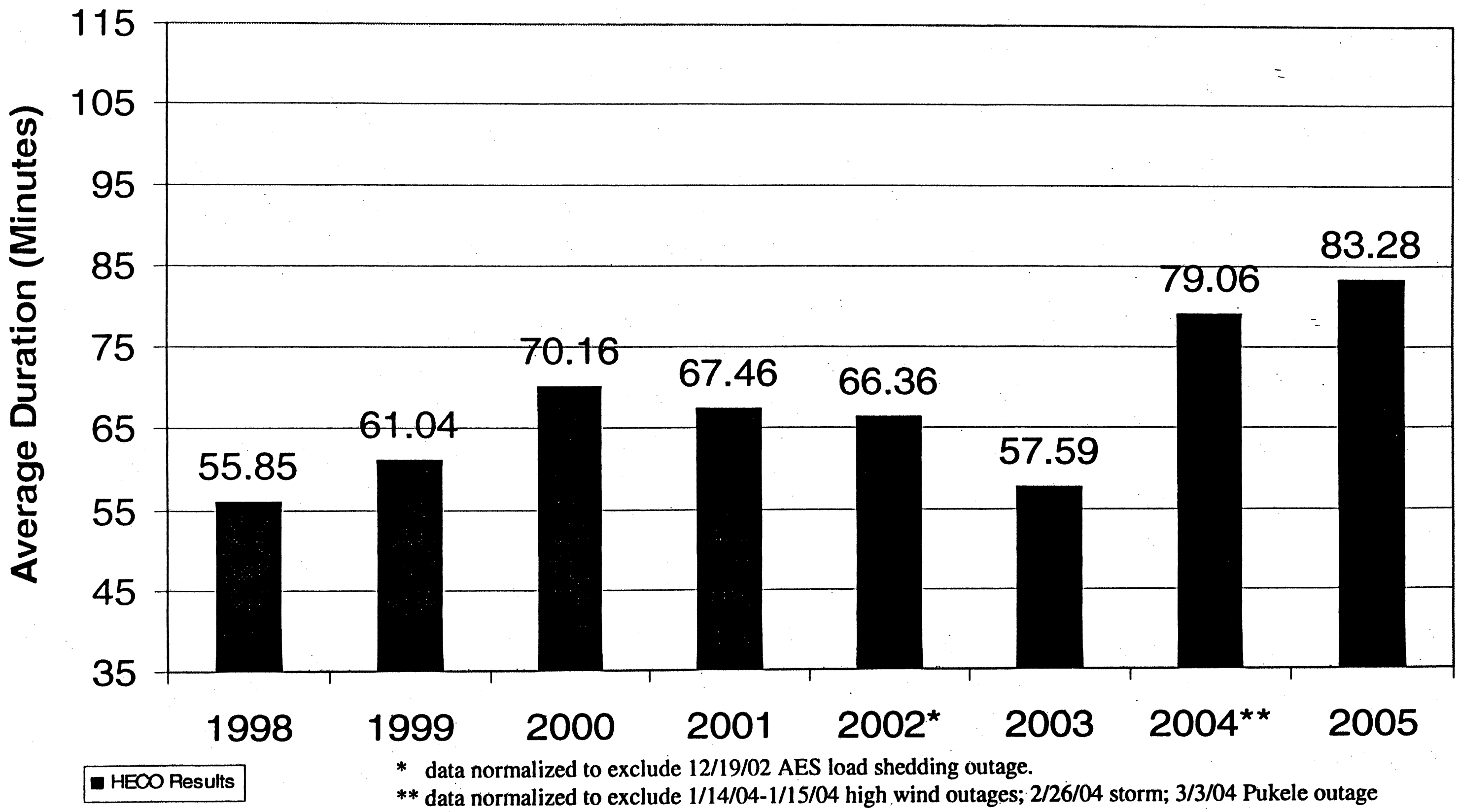
Hawaiian Electric Company, Inc.
System Average Interruption Frequency
SAIF
Lower is Better



* data normalized to exclude 12/19/02 AES load shedding outage.
** data normalized to exclude 1/14/04-1/15/04 high wind outages; 2/26/04 storm; 3/3/04 Pukele outage

Hawaiian Electric Company, Inc.
Customer Average Interruption Duration
CAID

Lower is Better

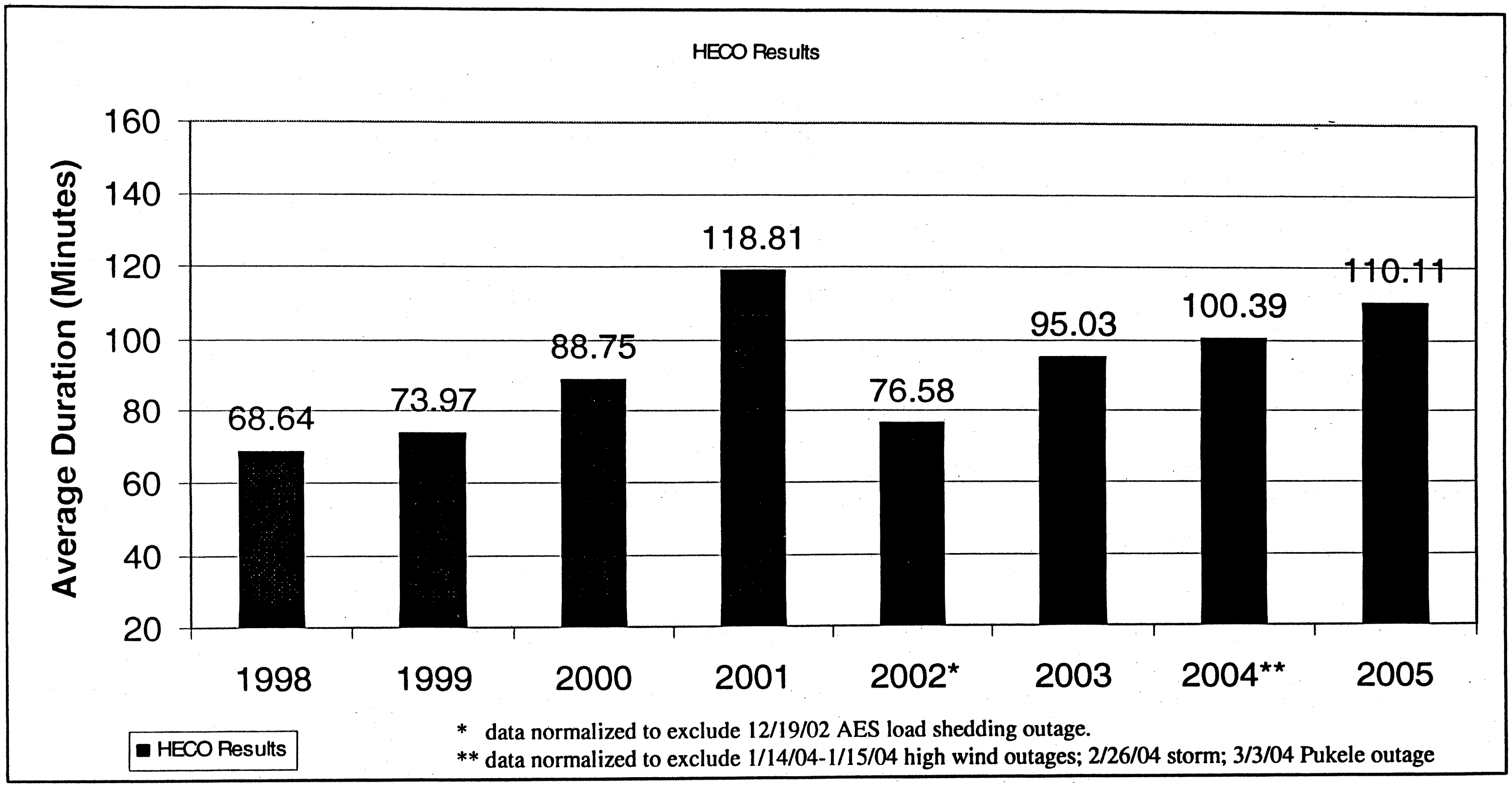


* data normalized to exclude 12/19/02 AES load shedding outage.

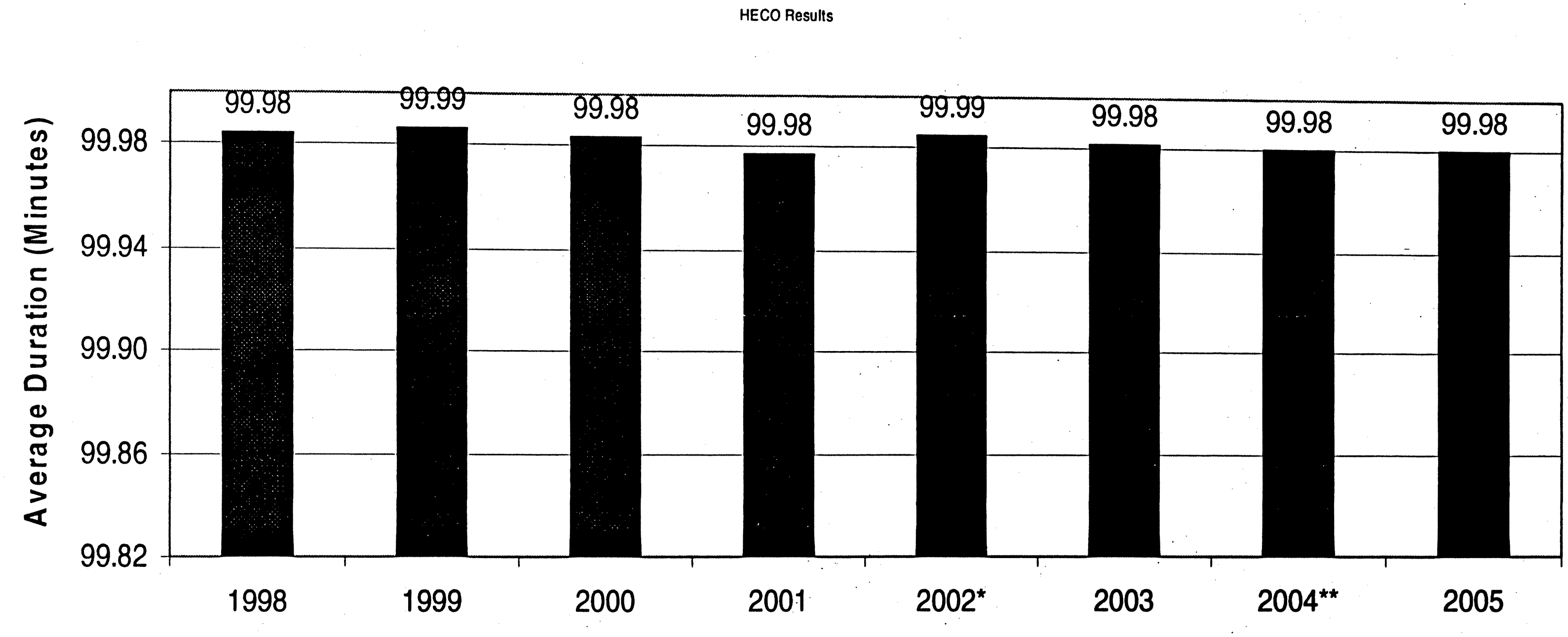
** data normalized to exclude 1/14/04-1/15/04 high wind outages; 2/26/04 storm; 3/3/04 Pukele outage

Hawaiian Electric Company, Inc.
System Average Interruption Duration
SAID

Lower is Better



Hawaiian Electric Company, Inc.
Average Service Availability
ASA
Higher is Better



* data normalized to exclude 12/19/02 AES load shedding outage.

** data normalized to exclude 1/14/04-1/15/04 high wind outages; 2/26/04 storm; 3/3/04 Pukele outage

Hawaiian Electric Co., Inc.
2007 TEST YEAR

TRANSMISSION & DISTRIBUTION SYSTEM RELIABILITY INDUSTRY INDICES

System Average Interruption Frequency (SAIF)

The number of customer interruptions per customer served during the year. This index indicates the average number of sustained interruptions experienced by all customers serviced on the system.

$$\text{SAIF} = \frac{\Sigma \text{ Number of Customer Interruptions Experienced During the Year}}{\text{Average Number of Customers Served During the Year}}$$

Customer Average Interruption Duration Index (CAID)

The interruption duration per customer interrupted during the year. This index indicates the average duration of an interruption for those customers affected by a sustained interruption.

$$\text{CAID} = \frac{\Sigma \text{ Duration of Interruptions X Number of Customers Affected}}{\Sigma \text{ Number of Customer Interruptions Experienced for the Year}}$$

System Average Interruption Duration Index (SAID)

The interruption duration per customer served during the year. This index indicates the average interruption time experienced by all customers serviced on the system.

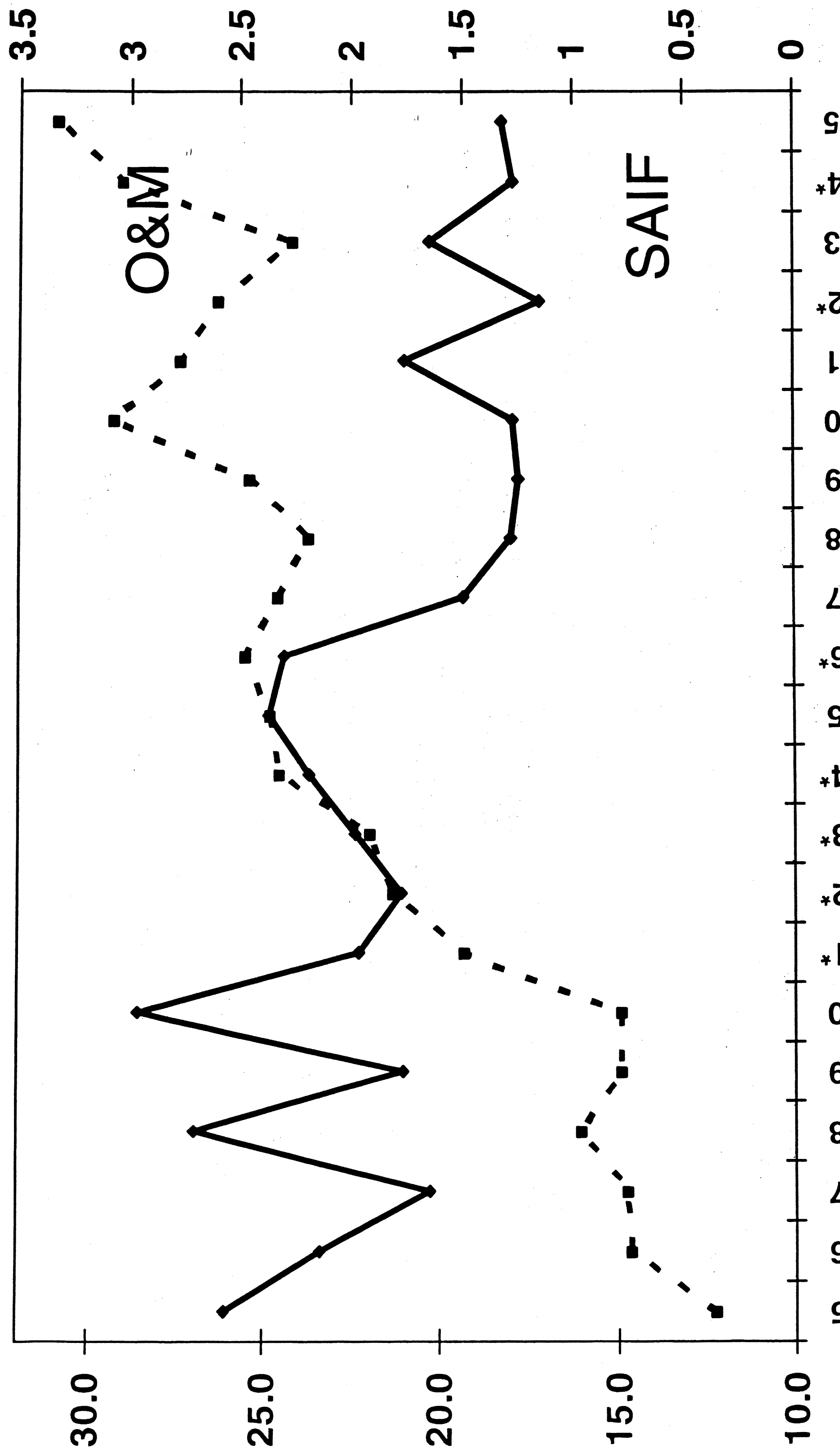
$$\text{SAID} = \frac{\Sigma \text{ Duration of Interruptions X Number of Customers Affected}}{\text{Average Number of Customers Served During the Year}}$$

Average Service Availability (ASA)

Total customer hours actually served as a percentage of total customer hours possible during the year. This indicates the extent to which electrical service was available to all customers. This index has been commonly referred to as the "Index of reliability." A customer-hour is calculated by multiplying the number of customers by the number of hours in the period being analyzed.

$$\text{ASA} = \frac{\Sigma \text{ Number of Customer Hours Actually Served during the Year}}{\Sigma\text{Number of Customer Hours Possible during the Year}}$$

Hawaiian Electric Company, Inc.
Investing in Reliability
SAIF and O&M Expenses

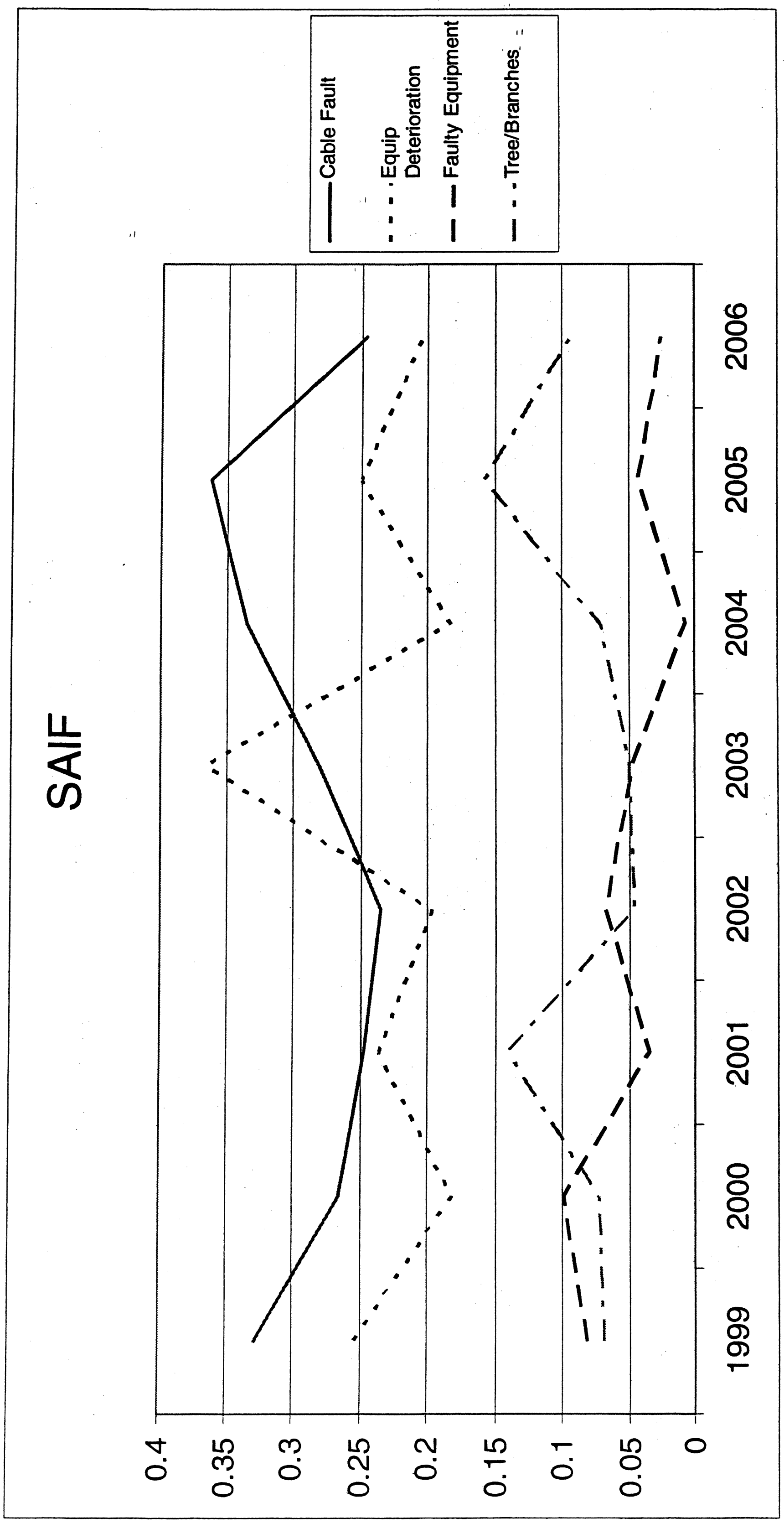


* Data normalized.- see page 2 for list of events

Hawaiian Electric Company, Inc.
SAIF Normalized Data Explanations

Year	Reason for Normalization
1991	April 9 – island wide blackout
1992	September 11 - Hurricane Iniki
1993	August 24 - Koolau pole fire
1994	October 30 - Pukele substation outage
1996	November 15 - AES load shedding
2002	December 19 - AES load shedding
2003	January 14-15, 2004 - high wind outages; February 26 - storm March 3 - Pukele outage

Hawaiian Electric Company, Inc.
Major Cause of Interruptions



Hawaiian Electric Company, Inc.
2007 Test Year

PERIOD ENDING STAFFING LEVELS

		RECORDED END OF YEAR		2006 YTD RECORDED	2006 EOY PROJECTED	TEST YEAR ESTIMATE
		(A) 2004	(B) 2005	(C) 9/30/2006	(D) 12/31/2006	(E) 2007
1	Construction & Maintenance	219	215	209	218	220
2	System Operation	100	112	108	105	117
3	Support Services	81	80	77	81	85
4	Engineering	79	86	85	84	85
5	VP - Energy Delivery	2	2	2	2	2
6	Total	481	495	481	490	509

Source:
Exhibit HECO-1403

Hawaiian Electric Company, Inc.
2007 TEST YEAR

Updated 10/2/2006

Price Indices Market Data	Comex Copper (per pound)	Midwest Aluminum (per pound)	WTI Crude Oil (per barrel)	Hot Rolled Steel Sheet (per short ton)	E-Steel Index (per short ton)
Jan-05	1.44995	0.90438	46.85	640	130.4183
Feb-05	1.46645	0.92810	48.05	622	127.3764
Mar-05	1.48680	0.97447	54.63	605	126.6160
Apr-05	1.49340	0.92990	53.22	575	122.8137
May-05	1.47580	0.85513	49.87	535	120.5323
Jun-05	1.62186	0.83887	56.42	495	121.6730
Jul-05	1.63218	0.85200	59.03	460	117.8707
Aug-05	1.71640	0.88529	64.99	435	150.4183
Sep-05	1.75357	0.87123	65.55	500	150.7985
Oct-05	1.90302	0.92019	62.27	535	153.0798
Nov-05	2.01130	0.97954	58.34	535	162.5856
Dec-05	2.17245	1.06958	59.45	550	164.4867
2005 avg.	1.68193	0.91739	56.56	541	137.3891
Jan-06	2.18258	1.13103	65.54	545	187.6806
Feb-06	2.25079	1.16849	61.93	545	184.0304
Mar-06	2.32409	1.15827	62.97	550	184.3346
Apr-06	2.96853	1.24583	70.16	560	181.3688
May-06	3.75861	1.35788	70.96	575	179.5437
Jun-06	3.39648	1.18455	70.97	605	180.2281
Jul-06	3.62321	1.19951	74.46	630	185.3992
Aug-06	3.53061	1.17549	73.08	630	186.6920
Sep-06	3.46358	1.17985	63.90	620	186.5399
ytd 2006 avg	3.05539	1.20010	68.22	584	183.9797
ytd 2006 increase over 2005 average	81.7%	30.8%	20.6%	8.1%	33.9%

Hawaiian Electric Company, Inc.
2007 TEST YEAR

2005 CORRECTION to T&D O&M EXPENSES
1999-2004 work expensed in fiscal year 2005

			1999	2000	2001	2002	2003	2004	TOTAL
	Transmission Operation								
1	Labor	$	-	-	-	-	-	-	$ -
2	Non-Labor	$	-	-	-	-	-	-	$ -
3	TOTAL	$	-	-	-	-	-	-	$ -
	Transmission Maintenance								
4	Labor	$	10,747	11,413	7,095	5,813	30,542	(4,564)	$ 61,046
5	Non-Labor	$	34,807	9,678	7,991	3,722	33,916	(3,228)	$ 86,886
6	TOTAL	$	45,554	21,091	15,086	9,535	64,458	(7,792)	$ 147,932
7=3+6	TOTAL TRANS O&M	$	45,554	21,091	15,086	9,535	64,458	(7,792)	$ 147,932
	Distribution Operation								
8	Labor	$	43,524	46,999	53,809	39,124	48,296	35,562	$ 267,314
9	Non-Labor	$	83,915	71,623	79,003	61,790	110,703	70,812	$ 477,846
10	TOTAL	$	127,439	118,622	132,812	100,914	158,999	106,374	$ 745,160
	Distribution Maintenance								
11	Labor	$	19,884	15,125	101,166	173,070	356,799	346,816	$ 1,012,860
12	Non-Labor	$	35,396	16,390	84,005	143,197	400,798	444,532	$ 1,124,318
13	TOTAL	$	55,280	31,515	185,171	316,267	757,597	791,348	$ 2,137,178
14=10+13	TOTAL DIST O&M	$	182,719	150,137	317,983	417,181	916,596	897,722	$ 2,882,338
15=7+14	GRAND TOTAL O&M	$	228,273	$ 171,228	$ 333,069	$ 426,716	$ 981,054	$ 889,930	$ 3,030,270

Hawaiian Electric Company, Inc.
2007 TEST YEAR

OAHU PRECIPITATION DATA

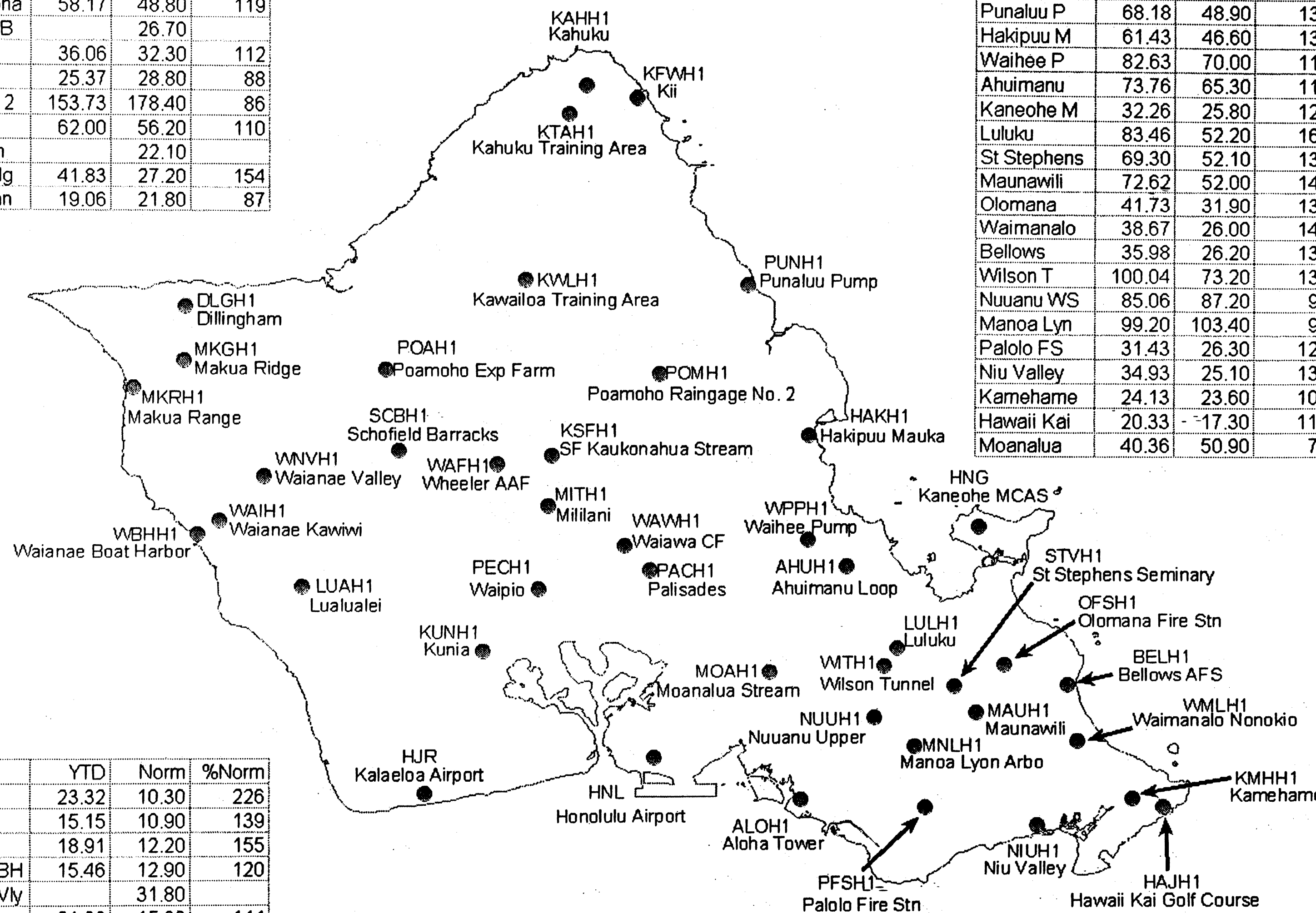
		2000		2001		2002		2003		2004		2005		2006*		
Location	Norm	YTD	% Norm	YTD	% Norm	YTD	% Norm	YTD	% Norm	YTD	% Norm	YTD	% Norm	YTD	Norm**	% Norm
Hnl Ap	22.00	7.11	32	9.16	42	12.19	66	12.67	69	39.02	212	15.61	71	23.32	10.3	226
Waianae	20.00	3.47	17	8.55	43	14.59	73	12.26	61	37.97	190	16.54	83	18.91	12.2	155
Makua Rdg	43.40									74.20	171	57.36	132	41.83	27.2	154
Hawaii Kai	28.00	10.95	39	11.33	40	21.70	78	25.48	91	46.74	167	27.48	98	20.33	17.3	118
Lualualei	25.00	9.62	38			17.77	71	24.85	99	39.83	159	18.77	75	21.98	15.3	144
Palolo Fs	40.00	24.59	61	25.90	65	24.27	61	26.85	67	62.59	156	39.68	99	31.43	26.3	120
Waimanalo	50.00	19.46	39			23.73	55	32.62	76	65.95	154	43.08	86	38.67	26	149
Waipio	30.00	16.17	54	17.83	59	21.07	70			45.75	153			22.30	18.8	119
Luluku	80.00	56.84	71	53.79	67	71.55	89	91.22	114	119.69	150	86.83	109	83.46	52.2	160
Schofield E	74.60									111.38	149					
Waianae BH	21.00									30.33	144	14.12	67	15.46	12.9	120
Mililani	45.00	27.10	60	31.51	70	36.13	80	42.01	93	62.22	138	50.22	112	36.51	28.9	126
Kunia Sub	28.00	10.90	39	9.81	35	15.05	54	20.98	75	38.07	136	16.75	60	21.30	17.2	124
Wilson Tunnel	110.00	89.87	82			107.63	98	120.43	109	147.05	134	107.45	98	100.04	73.2	137
Aloha Tower	25.00	8.66	35	11.85	47	13.45	54	15.07	60	32.66	131	17.3	69	21.55	15.5	139
St. Stephens	80.10							77.66	97	104.68	131	76.00	95	69.30	52.1	133
Olomana	50.00	29.12	58	30.46	61			35.71	71	65.58	131	39.85	80	41.73	31.9	131
Waianae Val.	49.10									63.44	129	26.58	54		31.8	
Bellows	40.20									51.93	129	28.09	70	35.98	26.2	137
Wheeler	50.00	24.87	50	36.33	73	37.17	74	45.54	91	63.10	126	42.85	86	36.06	32.3	112
Hakipuu M	75.00									94.78	126			61.43	46.6	132
Kahuku Tng	46.50									58.02	125	31.53	68	52.52	30.7	171
Maunawili	80.00	54.22	68	52.78	66	59.93	75	74.46	93	99.78	125	78.94	99	72.62	52	140
Waiawa	70.00			58.70	84	53.88	77	57.81	83	86.65	124	74.91	107	56.35	45.5	124
Kahuku	45.00	22.19	49	32.65	73	32.11	71	34.33	76	52.51	117	28.35	63	45.00	28.9	156
Kamehame	38.00	13.30	35	12.55	33	20.93	55	27.03	71	44.02	116	29.55	78	24.13	23.6	102
Punaluu P	75.00	40.96	55	40.29	54	54.84	73	50.47	67	85.49	114	61.83	82	68.18	48.9	139
Manoa Lyon	150.00	141.48	94	130.49	87	119.96	79	116.85	77	171.02	112	151.46	101	99.20	103.4	96
Palisades	75.00	42.25	56	51.65	69	48.36	64	54.24	72	81.56	109	63.16	84	55.89	48.6	115
Poamoho	45.00					24.78	55	29.23	65	48.66	108	30.29	67	25.37	28.8	88
Ahuimanu	100.00					75.19	75	92.16	92	106.71	107			73.76	65.3	113
Nuuanu Ws	130.00							101.91	78	138.94	107	124.56	96	85.06	87.2	98
Moanalua	80.00	41.04	51	50.18	63	39.76	50	46.01	58	79.70	100	57.62	72	40.36	50.9	79
Waihee P	115.00	50.40	44			80.51	70	98.57	86	105.80	94	80.00	70	82.63	70	118
Kaneohe M.	39.90							18.07	45	31.27	78	22.69	57	32.26	25.8	125
Kalaeloa	18.30							13.14	72					15.15	10.9	139
Schofield B	41.80							37.32	89						26.7	
Makua Ran	33.90							20.43	60					19.06	21.8	87
Waialua	33.80	12.48	37	13.21	39	21.33	71									
Kii	41.00											22.68	55	35.74	26.4	135
Niu Valley	40.00	22.90	57			32.17	80	36.84	92					34.93	25.1	139

* YTD as of August 2006
** YTD normal rainfall for period ending Aug 2006

Source:
National Oceanic Atmospheric Administration (NOAA)
Western Regional Climate Center, Rain Gauge Data
www.prh.noaa.gov/hnl

Hawaiian Electric Company
2007 Test Year
Oahu Precipitation Data

Location	YTD	Norm	%Norm
Waiawa	56.35	45.50	124
Palisades	55.89	48.60	115
Mililani	36.51	28.90	126
SF Kaukona	58.17	48.80	119
Schofield B		26.70	
Wheeler	36.06	32.30	112
Poamoho	25.37	28.80	88
Poamoho 2	153.73	178.40	86
Kawailoa	62.00	56.20	110
Dillingham		22.10	
Makua Rdg	41.83	27.20	154
Makua Ran	19.06	21.80	87



Location	YTD	Norm	%Norm
Kahuku	45.00	28.90	156
Kahuku Tng	52.52	30.70	171
Kii	35.74	26.40	135
Punaluu P	68.18	48.90	139
Hakipuu M	61.43	46.60	132
Waihee P	82.63	70.00	118
Ahuimanu	73.76	65.30	113
Kaneohe M	32.26	25.80	125
Luluku	83.46	52.20	160
St Stephens	69.30	52.10	133
Maunawili	72.62	52.00	140
Olomana	41.73	31.90	131
Waimanalo	38.67	26.00	149
Bellows	35.98	26.20	137
Wilson T	100.04	73.20	137
Nuuanu WS	85.06	87.20	98
Manoa Lyn	99.20	103.40	96
Palolo FS	31.43	26.30	120
Niu Valley	34.93	25.10	139
Kamehame	24.13	23.60	102
Hawaii Kai	20.33	17.30	118
Moanalua	40.36	50.90	79

Location	YTD	Norm	%Norm
HNL AP	23.32	10.30	226
Kalaeloa	15.15	10.90	139
Waianae	18.91	12.20	155
Waianae BH	15.46	12.90	120
Waianae Vly		31.80	
Lualualei	21.98	15.30	144
Kunia Sub	21.30	17.20	124
Waipio	22.30	18.80	119
Aloha Twr	21.55	15.50	139

Source: National Oceanic & Atmospheric Administration (NOAA)

Hawaiian Electric Company, Inc.
2007 Test Year
HECO Vegetation Management Budget Increase Justification
2007 – 2014

Cause	Factor	2005 Recorded	Change	Increase
Weather	1) Frequency of Trimming	$ 2,216,295	+21%	$ 473,756
Weather	2) Number of Units	$ 2,216,295	+11%	$ 225,668
Weather	3) Volume of Units	$ 2,216,295	+6%	$ 135,383
Weather (Indirect)	4) Increase Time per Unit	$ 2,216,295	+6%	$ 135,383
TOTAL			**+44%**	**$ 970,191**
2005 Recorded Amount	$ 2,216,295			
Increase to 2007 Operating Budget	$ 970,191			
TOTAL AMENDED ANNUAL BUDGET	**$ 3,186,486**			

Environmental Factors

Cause: Beginning in October 2003, precipitation statewide began increasing steadily with some locations reporting annual rainfalls of 200% or more of the amounts reported in the previous decade. The recent and most dramatic display of this trend occurred in March 2006, when rainfall on some Oahu sites exceeded 500% of normal. This increased precipitation, along with Hawaii's general sub-tropical climate, has significantly impacted the following factors of HECO's Vegetation Management program.

1) **Frequency of Trimming**
   Historically, HECO's Vegetation Management program operated on a 15 month Routine Maintenance (RM) cycle. Due to the increased precipitation and resultant growth, the current RM cycle length is 12 months or less resulting in approximately a 21% increase in program costs.

2) **Number of Units**
   HECO's Vegetation Management program historically addresses approximately 80,000 work units (trees) annually. Since precipitation has increased, HECO's Vegetation Management contractors have reported an approximately 11% (88,800 units) increase in the number of units needing treatment annually. Here, we see vegetation growing into the facilities that previously never required maintenance.

3) **Volume of Units**
   In addition to affecting maintenance frequency and total number of units managed, the increased rainfall has resulted in an increase in the overall volume of vegetation that requires removal from each unit. This effectively increases cost per unit, resulting in a 6% overall increase in management cost.

4) **Increase Time per Unit (Safety)**
   Lastly, due to decreased cycle length and the increased volume of biomass in close proximity to the conductors, the amount of time required to treat each unit in accordance with industry safety standards is increased by approximately 6%.

Conclusion

The increase in precipitation and its impact on associated environmental factors has resulted in an increased need of approximately 44% or $970,191 for HECO's Vegetation Management Program. As a result the 2007 operating budget for HECO's VM Program is $3,186,486.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

VEGETATION MANAGEMENT PROGRAM O&M EXPENSE

NARUC	NARUC DESCRIPTION	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 * projection	2006 budget	2007 estimate
571	Maint. OH lines - TRANS	730,941	493,836	512,382	504,541	598,698	480,651	1,320,181	660,286	836,952
593	Maint. OH lines - DISTR	1,542,797	1,544,897	1,335,908	1,895,205	1,700,985	1,735,644	1,823,576	2,065,341	2,349,534
		2,273,738	2,038,733	1,848,290	2,399,746	2,299,683	2,216,295	3,143,757	2,725,627	3,186,486

* 2006 projection includes recorded amounts year to date through November 2006 plus December 2006 estimated amount.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

VEGETATION MANAGEMENT PROGRAM O&M EXPENSE

	2000 Actual	2001 Actual	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 * projection	2006 budget	2007 estimate
Outside Contractors	2,103,235	1,839,800	1,739,059	2,142,713	2,000,395	1,880,366	2,816,197	2,405,004	3,008,468
HECO Labor	151,628	198,837	108,453	253,594	298,054	334,307	327,107	320,623	178,018
HECO Non-Labor	18,875	96	778	3,439	1,234	1,622	453	0	0
	2,273,738	2,038,733	1,848,290	2,399,746	2,299,683	2,216,295	3,143,757	2,725,627	3,186,486

* 2006 projection includes recorded amounts year to date through November, 2006, plus December 2006 estimated amount.

Hawaiian Electric Company, Inc.
2007 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A)	(B)	(C)	(B - C)
		ADJUSTED 2005 RECORDED	2006 *PROJECTION as of 11-30-06	2006 OPERATING BUDGET	2006 PROJECTED year end variance
	Transmission Operations				
1	Labor	$ 1,645	$ 2,177	$ 2,446	$ (269)
2	Non-Labor	$ 2,326	$ 2,132	$ 2,632	$ (500)
3	TOTAL	$ 3,971	$ 4,309	$ 5,078	$ (769)
	Transmission Maintenance				
4	Labor	$ 1,264	$ 1,866	$ 1,898	$ (32)
5	Non-Labor	$ 2,449	$ 3,190	$ 2,578	$ 612
6	TOTAL	$ 3,713	$ 5,056	$ 4,476	$ 580
7=3+6	TOTAL TRANS O&M	$ 7,684	$ 9,365	$ 9,554	$ (189)
	Distribution Operations				
8	Labor	$ 4,217	$ 4,624	$ 4,969	$ (345)
9	Non-Labor	$ 4,587	$ 4,246	$ 4,844	$ (598)
10	TOTAL	$ 8,804	$ 8,870	$ 9,813	$ (943)
	Distribution Maintenance				
11	Labor	$ 4,078	$ 5,551	$ 5,509	$ 42
12	Non-Labor	$ 7,277	$ 7,473	$ 7,772	$ (299)
13	TOTAL	$ 11,355	$ 13,024	$ 13,281	$ (257)
14=10+13	TOTAL DIST O&M	$ 20,159	$ 21,894	$ 23,094	$ (1,200)
15=7+14	GRAND TOTAL O&M	$ 27,843	$ 31,259	$ 32,648	$ (1,389)

* 2006 projection includes recorded amounts year to date through November 2006 plus December 2006 estimated amount.

Source:
HECO-734 for Column (A)

Hawaiian Electric Company, Inc.
2007 TEST YEAR

2005 TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A) 2005 ACTUAL	(B) 1999-2004 WORK ORDER ADJUSTMENTS	(C) 2005 ADJUSTED
	Transmission Operations			
1	Labor	$ 1,645	-	1,645
2	Non-Labor	$ 2,326	-	2,326
3	TOTAL	$ 3,971	-	3,971
	Transmission Maintenance			
4	Labor	$ 1,325	(61)	1,264
5	Non-Labor	$ 2,536	(87)	2,449
6	TOTAL	$ 3,861	(148)	3,713
7=3+6	TOTAL TRANS O&M	$ 7,832	(148)	7,684
	Distribution Operations			
8	Labor	$ 4,484	(267)	4,217
9	Non-Labor	$ 5,065	(478)	4,587
10	TOTAL	$ 9,549	(745)	8,804
	Distribution Maintenance			
11	Labor	$ 5,091	(1,013)	4,078
12	Non-Labor	$ 8,401	(1,124)	7,277
13	TOTAL	$ 13,492	(2,137)	11,355
14=10+13	TOTAL DIST O&M	$ 23,041	(2,882)	20,159
15=7+14	GRAND TOTAL O&M	$ 30,873	$ (3,030)	$ 27,843

Source:
HECO-WP-101(A), pages 3 and 4 for Column (A)
HECO-727 for Column (B)

Note:
Figures may not total exactly due to rounding.

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2005 RECORDED	LABOR 2007 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2005 RECORDED	NON-LABOR 2007 OPERATING BUDGET	NON-LABOR VARIANCE	2005 v. 2007 TOTAL VARIANCE Labor & Non-labor
Distribution Maintenance								
– Corrective OH transformer repl program.	P0000120	131,482	71,347	(60,135)	129,231	114,430	(14,801)	(74,936)
– Corrective UG transformer repl program	P0000121	72,294	63,447	(8,848)	74,441	96,760	22,319	13,471
– Corrective miscellaneous cable failures.	P0000122	83,035	143,269	60,234	231,950	226,399	(5,550)	54,684
– Corrective OH distribution repls.	P0000123	598,666	296,653	(302,013)	475,363	340,648	(134,715)	(436,728)
– Corrective OH subtransmission repls.	P0000124	0	0	0	0	0	0	0
– Vegetation management.	P0000126	87,561	35,244	(52,317)	1,640,823	2,314,289	673,466	621,149
– Test and treat wood poles.	P0000127	3,582	4,744	1,162	164,781	314,112	149,332	150,494
– Corrective maint of T&D system.	P0000359	2,259,782	1,879,955	(379,828)	3,111,827	3,128,729	16,902	(362,926)
– Preventive maint of T&D system.	P0000360	14,423	15,692	1,268	23,240	128,977	105,737	107,006
– Preventive inspection of T&D system.	P0000361	0	0	0	0	0	0	0
– PTM switching operations.	P0000740	202,654	269,458	66,804	241,563	357,643	116,080	182,883
– Preventive OH tsf repl.	P1789000	26,015	42,443	16,428	27,320	62,352	35,033	51,461
– Preventive UG tsf repl.	P1793000	33,549	33,957	409	40,472	55,703	15,231	15,639
– Preventive miscellaneous cable failure repl.	P1810000	56,105	55,086	(1,019)	122,317	70,295	(52,022)	(53,041)
– Preventive OH distribution repls.	P3400000	230,352	195,673	(34,679)	331,779	353,253	21,475	(13,204)
– Preventive OH subtransmission repls.	P3401000	277	0	(277)	358	0	(358)	(636)
Distribution Maintenance Total		3,799,776	3,106,965	(692,811)	6,615,464	7,563,591	948,127	255,316
Distribution Operation								
– Corrective OH distribution repls.	P0000123	418	0	(418)	464	0	(464)	(882)
– Corrective maint of T&D system.	P0000359	0	0	0	0	0	0	0
– Preventive maint of T&D system.	P0000360	20,265	17,082	(3,183)	21,259	22,672	1,413	(1,770)
– Preventive inspection of T&D system.	P0000361	472,286	820,495	348,209	698,585	1,020,841	322,255	670,464
– Corrective inspection of T&D system.	P0000362	65,319	170,599	105,280	79,198	241,108	161,910	267,190
– PTM switching operations.	P0000740	829,339	1,106,432	277,093	922,737	1,476,528	553,791	830,884
– Preventive OH distribution repls.	P3400000	374	0	(374)	476	0	(476)	(850)
Distribution Operation Total		1,388,001	2,114,607	726,607	1,722,720	2,761,149	1,038,429	1,765,036

2005 recorded program expenses have not been adjusted to account for work incorrectly charged to capital in 1999-2004 that was expensed in 2005.

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2005 RECORDED	LABOR 2007 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2005 RECORDED	NON-LABOR 2007 OPERATING BUDGET	NON-LABOR VARIANCE	2005 v. 2007 TOTAL VARIANCE Labor & Non-labor
Transmission Maintenance								
– Corrective OH transformer repl program.	P0000120	2,160	0	(2,160)	2,429	0	(2,429)	(4,589)
– Corrective miscellaneous cable failures.	P0000122	0	22,452	22,452	764	31,731	30,967	53,418
– Corrective OH subtransmission repls.	P0000124	80,392	54,277	(26,115)	58,298	69,256	10,958	(15,157)
– Corrective OH transmission repls.	P0000125	0	0	0	432	0	(432)	(432)
– Vegetation management.	P0000126	53,608	33,480	(20,128)	424,557	803,472	378,915	358,787
– Test and treat wood poles.	P0000127	1,780	1,579	(201)	110,143	60,626	(49,517)	(49,718)
– Corrective maint of T&D system.	P0000359	63,657	0	(63,657)	70,359	0	(70,359)	(134,017)
– Preventive maint of T&D system.	P0000360	5,569	18,068	12,498	9,565	59,476	49,911	62,409
– Preventive inspection of T&D system.	P0000361	154	0	(154)	163	0	(163)	(317)
– Preventive miscellaneous cable failure repl.	P1810000	0	0	0	0	0	0	0
– Preventive OH distribution repls.	P3400000	0	0	0	0	0	0	0
– Preventive OH subtransmission repls.	P3401000	68,652	217,305	148,653	105,127	338,252	233,126	381,778
– Preventive OH transmission repls.	P3402000	29,422	22,943	(6,479)	426,637	41,082	(385,555)	(392,034)
Transmission Maintenance Total		**305,394**	**370,103**	**64,709**	**1,208,473**	**1,403,895**	**195,421**	**260,130**
Transmission Operation								
– Preventive maint of T&D system.	P0000360	0	0	0	0	0	0	0
– Preventive inspection of T&D system.	P0000361	71,411	387,303	315,891	675,602	764,571	88,969	404,861
– Corrective inspection of T&D system.	P0000362	14,275	0	(14,275)	20,928	0	(20,928)	(35,203)
– PTM switching operations.	P0000740	40,082	47,479	7,397	41,217	68,018	26,801	34,198
– Preventive OH subtransmission repls.	P3401000	0	0	0	0	0	0	0
– Preventive OH transmission repls.	P3402000	0	0	0	0	0	0	0
Transmission Operation Total		**125,769**	**434,782**	**309,013**	**737,746**	**832,589**	**94,842**	**403,855**
COMBINED TOTAL (Trans & Dist / Oper & Maint)								
– Corrective OH transformer repl program.	P0000120	133,642	71,347	(62,296)	131,660	114,430	(17,230)	(79,526)
– Corrective UG transformer repl program	P0000121	72,294	63,447	(8,848)	74,441	96,760	22,319	13,471
– Corrective miscellaneous cable failures.	P0000122	83,035	165,720	82,686	232,714	258,130	25,416	108,102

2005 recorded program expenses have not been adjusted to account for work incorrectly charged to capital in 1999-2004 that was expensed in 2005.

PROGRAM DESCRIPTION	PROJECT NUMBER	LABOR 2005 RECORDED	LABOR 2007 OPERATING BUDGET	LABOR VARIANCE	NON-LABOR 2005 RECORDED	NON-LABOR 2007 OPERATING BUDGET	NON-LABOR VARIANCE	2005 v. 2007 TOTAL VARIANCE Labor & Non-labor
– Corrective OH distribution repls.	P0000123	599,084	296,653	(302,431)	475,827	340,648	(135,179)	(437,610)
– Corrective OH subtransmission repls.	P0000124	80,392	54,277	(26,115)	58,298	69,256	10,958	(15,157)
– Corrective OH transmission repls.	P0000125	0	0	0	431.53	0	(432)	(432)
– Vegetation management.	P0000126	141,169	68,724	(72,445)	2,065,380	3,117,761	1,052,380	979,936
– Test and treat wood poles.	P0000127	5,361	6,322	961	274,924	374,738	99,815	100,776
– Corrective maint of T&D system.	P0000359	2,323,439	1,879,955	(443,485)	3,182,186	3,128,729	(53,457)	(496,942)
– Preventive maint of T&D system.	P0000360	40,258	50,841	10,583	54,064	211,125	157,061	167,645
– Preventive inspection of T&D system.	P0000361	543,851	1,207,797	663,947	1,374,350	1,785,412	411,062	1,075,009
– Corrective inspection of T&D system.	P0000362	79,594	170,599	91,005	100,125	241,108	140,982	231,987
– PTM switching operations.	P0000740	1,072,075	1,423,369	351,294	1,205,517	1,902,188	696,671	1,047,965
– Preventive OH tsf repl.	P1789000	26,015	42,443	16,428	27,320	62,352	35,033	51,461
– Preventive UG tsf repl.	P1793000	33,549	33,957	409	40,472	55,703	15,231	15,639
– Preventive miscellaneous cable failure repl.	P1810000	56,105	55,086	(1,019)	122,317	70,295	(52,022)	(53,041)
– Preventive OH distribution repls.	P3400000	230,726	195,673	(35,053)	332,255	353,253	20,999	(14,055)
– Preventive OH subtransmission repls.	P3401000	68,929	217,305	148,375	105,485	338,252	232,767	381,143
– Preventive OH transmission repls.	P3402000	29,422	22,943	(6,479)	426,637	41,082	(385,555)	(392,034)
GRAND TOTAL		5,618,940	6,026,458	407,518	10,284,403	12,561,224	2,276,820	2,684,338

2005 recorded program expenses have not been adjusted to account for work incorrectly charged to capital in 1999-2004 that was expensed in 2005.

DESCRIPTION	PROJECT NUMBER	2001 ACTUAL	2002 ACTUAL	2003 ACTUAL	2004 ACTUAL	2005 ACTUAL	2006 FORECAST	2007 BUDGET
– Corrective OH transformer repl program.	P0000120	76,971	190,551	128,679	187,420	265,302	171,401	185,777
– Corrective UG transformer repl program	P0000121	91,199	174,099	96,501	135,579	146,735	115,515	160,206
– Corrective miscellaneous cable failures.	P0000122	72,536	18,183	104,177	257,406	315,748	267,753	423,850
– Corrective OH distribution repls.	P0000123	267,089	281,482	331,769	624,447	1,074,911	478,993	637,301
– Corrective OH subtransmission repls.	P0000124	43,219	55,371	120,400	110,388	138,691	104,970	123,533
– Corrective OH transmission repls.	P0000125	0	522	0	0	432	0	0
– Vegetation management.	P0000126	1,721,057	1,809,762	2,384,558	2,289,940	2,206,549	2,718,938	3,186,485
– Test and treat wood poles.	P0000127	77,950	194,321	204,857	257,694	280,285	379,328	381,061
– Corrective maint of T&D system.	P0000359	3,467,095	4,421,216	2,476,398	4,047,311	5,505,626	4,636,865	5,008,683
– Preventive maint of T&D system.	P0000360	778,021	757,944	373,962	117,500	94,322	671,426	261,967
– Preventive inspection of T&D system.	P0000361	1,142,647	1,294,526	1,533,435	2,130,278	1,918,200	2,751,389	2,993,209
– Corrective inspection of T&D system.	P0000362	5,310	10,231	151,462	-2,095	179,720	375,852	411,707
– PTM switching operations.	P0000740	0	0	1,307,852	1,980,646	2,277,592	3,235,090	3,325,557
– Preventive OH tsf repl.	P1789000	126,012	100,395	44,908	31,590	53,335	104,402	104,796
– Preventive UG tsf repl.	P1793000	183,359	84,784	70,629	99,404	74,021	88,969	89,660
– Preventive miscellaneous cable failure repl.	P1810000	145,885	174,195	364,281	12,443	178,422	114,861	125,381
– Preventive OH distribution repls.	P3400000	1,144,463	1,031,761	490,672	532,907	562,981	506,871	548,926
– Preventive OH subtransmission repls.	P3401000	362,293	444,654	169,755	153,086	174,414	509,275	555,557
– Preventive OH transmission repls.	P3402000	3,974	6,535	144,042	170,508	456,059	59,105	64,025
TOTAL O&M		9,709,080	11,050,532	10,498,337	13,136,452	15,903,343	17,291,004	18,587,681

2005 recorded program expenses have not been adjusted to account for work incorrectly charged to capital in 1999-2004 that was expensed in 2005.

Hawaiian Electric Company, Inc.
2007 Test Year

OUTAGE MANAGEMENT SYSTEM (OMS) PROJECT COSTS

Description of Cost	Initial Project Forecast				Project Actuals-to-date as of 11-30-2006			
	Capital	**Deferred**	**Expense**	**Total Estimate**	**Capital Actuals**	**Deferred Actuals**	**Expense Actuals**	**Total Actuals**
Pre-selection/evaluation and PUC reporting			$285,556	**$285,556**			$611,035	**$611,035**
Convert data from current system to new			$686,451	**$686,451**			$244,692	**$244,692**
Training material development & training sessions			$85,873	**$85,873**			$52,977	**$52,977**
Overhead on Expense Items			$82,820	**$82,820**			$219,826	**$219,826**
Maintenance on Software							$168,014	**$168,014**
Other internal & external labor costs		$291,204		**$291,204**		$593,023		**$593,023**
Software license fees		$1,274,366		**$1,274,366**		$621,135		**$621,135**
Inter-island travel, lodging and per diem		$1,771,599		**$1,771,599**		$1,495,586		**$1,495,586**
Other costs		$66,010		**$66,010**		$0		**$0**
AFUDC on Deferred Items		$398,565		**$398,565**		$140,271		**$140,271**
Overhead on Deferred Items		$504,721		**$504,721**		$0		**$0**
Hardware	$353,436			**$353,436**	$321,433			**$321,433**
Other costs	$19,980			**$19,980**	$0			**$0**
AFUDC on Capital Items	$21,300			**$21,300**	$0			**$0**
Total	$394,716	$4,306,466	$1,140,702	**$5,841,883**	$321,433	$2,850,015	$1,296,544	**$4,467,992**

	CAPITAL	DEFERRED	EXPENSE	**TOTAL**
Project Actuals-to-date as of 11-30-2006	$321,433	$2,850,015	$1,296,544	**$4,467,992**
Remaining Forecast: 12/06-09/07, *rev. 11/06*				
Software Maintenance			$113,520	
Training (Labor & Outside Services)			$453,279	
Data Clean Up			$15,000	
AFUDC on deferred expense		$43,726		
SPL Software License		$123,314		
Outside Services (including SPL and Kema)		$908,875		
HECO labor including overheads		$305,668		
Remaining Forecast: 12/06 - 09/07 Total	$36,603	$1,381,583	$581,799	**$1,999,985**
TOTAL REVISED ESTIMATE:	$358,036	$4,231,598	$1,878,343	**$6,467,977**

Hawaiian Electric Company, Inc.
2007 Test Year

OUTAGE MANAGEMENT SYSTEM (OMS) PROJECT COSTS

	Description of Cost	Actual 2003 Subtotal	Actual 2004 Subtotal	Actual 2005 Subtotal	Actual 2006 Jan-Nov Subtotal	Project Actuals-to-date as of 11-30-06: Capital Actuals	Deferred Actuals	Expense Actuals	Total Actuals
1	Pre-selection/evaluation and PUC reporting	$17,339	230,195	335,466	28,035			$611,035	**$611,035**
2	Convert data from current system to new			79,441	165,251			$244,692	**$244,692**
3	Training material development & training sessions			23,864	29,113			$52,977	**$52,977**
4	Overhead on Expense Items			40,427	179,399			$219,826	**$219,826**
5	Maintenance on Software			80,225	87,789			$168,014	**$168,014**
6	Other internal & external labor costs			244,681	348,342		$593,023		**$593,023**
7	Software license fees			192,379	428,756		$621,135		**$621,135**
8	Inter-island travel, lodging and per diem			243,120	1,252,466		$1,495,586		**$1,495,586**
9	Other costs						$0		**$0**
10	AFUDC on Deferred Items			11,153	129,118		$140,271		**$140,271**
11	Overhead on Deferred Items						$0		**$0**
12	Hardware			8,055	313,378	$321,433			**$321,433**
13	Other costs					$0			**$0**
14	AFUDC on Capital Items					$0			**$0**
	Total	$17,339	230,195	1,258,811	2,961,647	$321,433	$2,850,015	$1,296,544	**$4,467,992**

Description of C&M Programs

The purpose of the following programs is to maintain or improve system reliability, power quality and customer satisfaction by restoring service or the system to its prior or an upgraded condition.

P0000120 – Corrective overhead transformer replacement program. The purpose of the program is the repair or replacement of overhead transformers that have been identified as failed due to being rusted, leaking, overloaded or damaged by an outside party.

P0000121 – Corrective underground transformer replacement program. The purpose of the program is the repair or replacement of underground padmount transformers that have been identified as failed due to being rusted, leaking, overloaded or damaged by an outside party.

P0000122 – Corrective miscellaneous cable failures. The purpose of the program is the corrective repair or replacement of underground primary, secondary, service and transmission cables, including damages due to a dig-in by outside parties. The replacement cable may be of greater capacity and/or higher voltage rating to accommodate future conditions

P0000123 – Corrective overhead distribution replacements. The purpose of the program is the repair or replacement of overhead distribution poles and associated equipment, including cutouts, aerial cables, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000124 – Corrective overhead subtransmission replacements. The purpose of the program is the repair or replacement of overhead subtransmission poles and associated equipment, including anchors, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000125 – Corrective overhead transmission replacements. The purpose of the program is the repair or replacement of overhead transmission poles and associated equipment, including anchors, conductors and fixtures that have been identified as broken, rusted, corroded, rotten or damaged. This is to restore service or the system to its original condition or an upgraded condition.

P0000126 – Vegetation management. This program is to manage vegetation along HECO roadside, right-of-way and other facilities to ensure safe and reliable service can be provided. This includes cutting, trimming and controlling trees, vines and other

Description of C&M Programs

undesirable vegetation to ensure easy and safe access for inspections, maintenance and repairs of facilities.

P0000127 – Test and treat wood poles. This program involves the inspection of wood poles by sounding and boring to determine the condition of the poles and then treatment of the poles with insecticide or fungicide. The program will identify and correct any potential damage by termites or wood rot, which will prolong the life of the pole and reduce replacement costs and outages caused by pole failures.

P0000359 – Corrective maintenance of T&D system. The program is to make minor miscellaneous temporary or permanent repairs or adjustments to unsafe equipment that has failed and poses a danger to customers.

P0000360 – Preventive maintenance of T&D system. The program is to make minor miscellaneous planned repairs, replacements or improvements of overhead and underground equipment that has been identified as deteriorated or damage and not up to standard.

P0000361 – Preventive inspection of T&D system. The purpose of the program is the overhead and underground inspections of the transmission and distribution system to identify potential repairs, replacements or improvements of equipment. This program should identify deteriorated and/or broken equipment before it fails and leads to outages.

P0000362 – Corrective inspection of T&D system. The purpose of the program is the corrective inspection to determine the cause of interruptions or outages to improve system reliability and power quality.

P0000740 – PTM switching operations. This program is being created to capture PTM responsibilities not related to a specific program or project, including emergency or accident investigations, minor repairs and trouble calls.

P1789000 – Preventive overhead transformer replacement. The purpose of the program is the planned repairs or replacement of overhead transformers that have been identified due to rusting, potential future overloading conditions or as part of a planned pole replacement/upgrade.

P1793000 – Preventive underground transformer replacement. The purpose of the program is the planned repairs or replacement of underground padmount transformers that have been identified due to rusting, potential future overloading conditions or as part of a planned pole replacement/upgrade.

Description of C&M Programs

P181000 – Preventive miscellaneous cable failure replacement. The purpose of the program is the planned replacement of underground cables that have been identified as needing replacement due to excessive faulting.

P3400000 – Preventive overhead distribution replacements. The purpose of the program is the repair or replacement of overhead distribution poles and associated equipment, including cutouts, aerial cables, conductors and fixtures prior to failure.

P3401000 – Preventive overhead subtransmission replacements. The purpose of the program is the repair or replacement of overhead subtransmission poles and associated equipment, including anchors, conductors and fixtures prior to failure.

P3402000 – Preventive overhead transmission replacements. The purpose of the program is the repair or replacement of overhead transmission poles and associated equipment, including anchors, conductors and fixtures prior to failure.

TESTIMONY OF
DARREN S. YAMAMOTO

MANAGER
CUSTOMER SERVICE DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Customer Accounts Expense
Customer Deposits
Interest on Customer Deposits
Revenue Lag Days
Non-Sales Electric Utility Charges

INTRODUCTION

Q. Please state your name and business address.

A. My name is Darren S. Yamamoto and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Customer Service Department for Hawaiian Electric Company, Inc. ("HECO"). My experience and educational background are listed in HECO-800.

Q. What is your area of responsibility in this testimony?

A. My testimony will cover HECO's 2007 test year estimate of:

1) Customer Accounts Expense, which includes the following four accounts:
   a) Account No. 901 – Supervision;
   b) Account No. 902 – Meter Reading;
   c) Account No. 903 – Customer Records and Collections; and
   d) Account No. 904 – Uncollectibles.

My testimony will also describe:

2) Customer Deposits and Interest on Customer Deposits;
3) Revenue Lag Days; and
4) Non-Sales Electric Utility Charges (excluding Payment Protection Program and Purchase Power Metering charges).

Q. What is HECO's test year estimate of Customer Accounts Expense?

A. As shown on HECO-801, page 1, the 2007 test year estimate of Customer Accounts Expense is $13,378,000, at present rates, and $13,431,000 at present rates with the interim surcharge, $13,531,000 at proposed rates. The three estimates are explained in further in my testimony.

Q. What are HECO's estimates of Customer Deposits and Interest on Customer Deposits for the 2007 test year?

A. The 2007 test year estimate for Customer Deposits is $6,377,000 as shown on HECO-802. Based on this estimate of customer deposits, the test year estimate of interest on customer deposits is $375,000, as shown on HECO-803.

Q. What level of revenue lag days is proposed for test year 2007?

A. HECO estimates the test year revenue lag days to be 37 days as calculated in HECO-WP-804. In the calculation of working cash, Ms. Gayle Ohashi (HECO T-17) uses the revenue lag days estimate.

Q. What are HECO's estimates of Non-Sales Electric Utility Charges, excluding the Payment Protection Program and Purchase Power Metering Charges?

A. The 2007 test year estimates for Non-Sales Electric Utility Charges, excluding the Payment Protection Program and Purchase Power Metering Charges, at present rates, present rates with the interim surcharge, and proposed rates are $2,202,100 , $2,251,500, and $ 3,021,300 respectively, as reflected in HECO-807. The three estimates are explained in further in my testimony.

Q. Who is responsible for the test year estimates of Payment Protection Program and Purchase Power Metering Charges?

A. Discussion of these charges is included in Mr. Bruce Tamashiro's direct testimony, HECO T-13.

<u>CUSTOMER ACCOUNTS EXPENSE EXCLUDING UNCOLLECTIBLES EXPENSE</u>

Q. What is the test year estimate of Customer Accounts Expense, excluding uncollectibles expense?

A. HECO's test year Customer Accounts total expense estimate, excluding uncollectibles expense, is $12,020,000 as shown on HECO-801, page 1.

Q. What expenses are included as Customer Accounts Expense, excluding uncollectibles expense?

A. These expenses are primarily related to providing, managing and maintaining services and information for customer account services and customer account management. These activities include:

1) receiving and responding to customer calls and requests;
2) processing customer requests to start, change or terminate service;
3) meter reading;
4) field services and field investigations;
5) monthly billing (calculation and physical rendering);
6) collecting and processing of payments;
7) managing delinquent accounts; and
8) maintaining customer records.

The costs for these activities are recorded in Account No.s 901, 902, and 903, which are described in HECO-WP-801, page 1.

Q. How did HECO develop its test year estimate for these expenses?

A. The test year expenses are based on HECO's Operations and Maintenance ("O & M") expense budget for 2007.

Q. How was the O & M expense budget for Customer Accounts Expense prepared?

A. HECO prepared its O & M expense budget as follows. First, staffing requirements were determined based on forecasted operational and workload requirements. Second, labor expenses for bargaining unit and salaried (merit) employees were estimated based on the wage and salary assumptions as discussed by Ms. Patsy Nanbu in HECO T-10. Third, nonlabor expenses were based on historical costs that are updated for anticipated 2007 price increases. The development of labor and nonlabor costs for each account is detailed further in my testimony.

Q. What adjustments were made to the 2007 test year budget to determine the test year estimates?

A. The following adjustments totaling an increase of $19,000 were made to Account No. 903 and are reflected on HECO-801:

1) A decrease of $74,000 of labor expenses to reflect the department's revised staffing plan;
2) An increase of $63,000 in non labor expenses to hire temporary agency workers to support operational needs during the hiring lag and assignment of personnel to the Customer Information Project; and
3) An increase of $30,000 in nonlabor expenses for abandoned projects.

I discuss these adjustments later in my testimony.

Q. How do the 2007 test year Customer Accounts Expenses, excluding uncollectibles expense, compare to expenses in previous years?

A. The 2007 test year expenses are higher by $1,210,000 than recorded for 2005. The reasons for this increase by account are explained further in my testimony.

<u>Employee Count</u>

Q. How many employees are included in the 2007 test year labor expense?

A. There is an average of 131 employees reflected in the test year as indicated on HECO-804, excluding the employees in the Senior Vice President Operations office. Ms. Faye Chiogioji discusses the estimated employee count for the Senior Vice President Operations office in HECO T-14.

Q. How does the test year labor force compare to previous years?

A. The actual average, highest, and end-of–year ("EOY") employee counts are as follows:

Year	Average	High	EOY
2001	120	120	118
2002	116	117	118
2003	115	116	110
2004	119	128	126
2005	129	132	130
2007*	131	133	133

*Forecasted

The test year EOY staffing level of 133 is a net increase of three positions over the 130 actual employees hired at the EOY 2005 and only one more than the highest actual number of positions that were filled in the same year.

Q. What are the three vacant positions and to what accounts are these positions budgeted in the test year?

A. The three vacant positions are for an operations analyst, a call center supervisor, and an accounts services clerk. These positions are budgeted in Account 903, Customer Records and Collections Expense.

Q. Please summarize the need for the increased level of staffing in the test year.

A. The 2007 test year staffing level reflects very little growth in employee positions from the level and number of staff and resources required in 2005, even with the Company's growing customer base. The filling of these vacant positions for replacement of staff will allow the Company to continue to maintain its daily operations and provide for new or additional work and projects during the test year.

Q. Please provide examples of the new or additional work that Customer Accounts plans to undertake in 2007.

A. Due to the new identity theft laws, the department plans to develop new procedures and processes to handle confidential documents and customer information in 2007. Also, the department is reviewing revenue protection processes that are needed to safeguard against actions such as meter tampering.

<u>Account No. 901 - Supervision</u>

Q. What is the 2007 test year expense estimate for Account No. 901 – Supervision?

A. HECO's test year Account No. 901 – Supervision expense estimate is $1,358,000, as shown in HECO-801, page 1. This includes $154,000 for labor and $1,204,000 for non-labor expenses. (See HECO-801, page 2.)

Q. What labor expenses are included in Account No. 901 – Supervision?

A. This account includes the projected labor costs for the Customer Service Department manager and secretary.

Q. What non-labor expenses are included in Account No. 901 – Supervision?

A. This account includes nonlabor costs for operational initiatives (i.e., technical improvements, customer initiatives, and operations projects) and in-house Information Technology support services.

Q. How does the 2007 test year expense estimate for Account No. 901 – Supervision compare with the recorded 2005 expense?

A. The 2007 test year is $385,000 higher than the recorded 2005 expense.

Q. What is the reason for the increase in the 2007 test year expense estimate over the 2005 recorded expense?

A. The 2005 labor costs recorded in Account No. 901 were lower because more of the manager's time was charged to Account No. 903 in that year. The test year budget reflects a more appropriate allocation than what was recorded in 2005. The increase in the non-labor expense is primarily due to higher budgeted software maintenance and software costs that are a result of a modified allocation of information technology services costs that was implemented in 2005. Ms. Patsy Nanbu provides more detail of the modified allocation of these costs in HECO T-10.

<u>Account No. 902 – Meter Reading</u>

Q. What is the 2007 test year expense estimate for Account No. 902 – Meter Reading?

A. HECO's test year 2007 expense estimate for Account No. 902 – Meter Reading is $2,693,000, as shown in HECO-801, page 1. This includes labor expense estimates of $2,237,000 and non-labor expense estimates of $456,000, as shown in HECO-801, page 2.

Q. What expenses are included in Account No. 902 – Meter Reading's $2,237,000 labor expense estimate for test year 2007?

A. Meter Reading labor expense includes the labor cost for:

1) thirty-two meter readers;
2) one clerk;
3) one supervisor;
4) one translation system coordinator;
5) 25% of the labor expense for the director of Customer Field Services; and
6) the Field Services Section labor expense related to the "rereading" of meters for billing purposes.

Q. How does the test year 2007 labor expense estimate for Account No. 902 compare with the recorded 2005 labor expense?

A. The test year estimate is $385,000 higher than the 2005 recorded labor expense.

Q. What are the reasons for the increased labor expense in the 2007 test year?

A. The primary reasons for the increase in estimated labor cost for the 2007 test year are:

1) contractual bargaining unit and salaried employee wage increase as discussed in Ms. Patsy Nanbu's testimony in HECO T-10; and

2) lower 2005 labor costs due to new hires experiencing "time-in-grade wage increases", i.e., where meter readers get increases over a six month period to reach their top wage tier for the hourly rate.

Q. Are more meter readers included in the 2007 labor estimate than the actual number employed in 2005?

A. No. The 32 meter reader positions reflected in the 2007 labor estimate is very close to the actual number of meter readers employed in 2005. Through technological advances and the careful use of overtime, HECO has been able to sustain this level of staffing over the last several years. Some of these technological advances include the automation of portions of the meter reading routes in Kahala, Aiea, Waikele and Ewa. These automated routes consist of meters with electronic reading devices that allow quicker and more accurate meter reads using a drive-by wireless reading system and radio wave frequency. These routes would normally require 96 work hours a month to read. With the new system, more than 3,000 meters can be read within 24 work hours.

Q. What expenses are included in Account No. 902's $456,000 non-labor expense estimate for the 2007 test year?

A. The 2007 test year meter reading non-labor expenses include the costs of vehicle operation and maintenance, maintenance for the meter reading devices used to record meter readings in the field, the support equipment used to transfer those readings from the meter reading devices to the mainframe computer, company identification uniforms, and miscellaneous supplies such as meter seals required by the meter readers.

Q. How does the 2007 test year non-labor expense estimate compare with the amount recorded in 2005?

A. The test year is $116,000 higher than 2005 recorded expense.

Q. What is the reason for this increase?

A. The increase in 2007 test year expenses reflects normal levels of operating expenses and the expected increase in operations and workload due to the continued increase in customer accounts, customer meters and customer service requests and related work.

<u>Account No. 903 – Customer Records and Collection Expense</u>

Q. What is the 2007 test year expense estimate for Account No. 903 – Customer Records and Collection Expense?

A. HECO's test year Account No. 903 – Customer Records and Collection Expense estimate is $7,969,000 as shown on HECO-801, page 1. This includes $4,274,000 of labor and $3,695,000 of non-labor expenses, as shown on HECO-801, page 2.

Q. Were any budget adjustments made to the 2007 test year estimate for ratemaking purposes?

A. Yes. There were three separate budget adjustments, a decrease of $74,000 in labor expenses, an increase of $63,000 in non labor expenses for the temporary hiring of agency workers, and an increase of $30,000 in non labor expenses for abandoned projects. This resulted in a net increase of $19,000.

Q. Please explain the labor adjustment of $74,000.

A. This decrease was made to reflect the updated staffing plan throughout the 2007 test year. Based on the 2006 EOY Customer Accounts employee count projection as discussed by Ms. Faye Chiogioji in HECO-T-14 and discussions with the Corporate Excellence department, Customer Accounts reduced its 2007 employee count by one and refined its timeline of anticipated hires during the test year. This resulted in the decrease of $74,000 in labor expenses.

Q. Please explain the non-labor adjustment for hiring temporary workers of $63,000.

A. This increase reflects the added cost of two temporary positions.

Q. Why is it necessary to hire these two temporary workers?

A. These positions will supplement the current staff to maintain operational integrity while the Department is in the process of filling the vacant positions. Also the temporary workers are required to do the work normally performed by the regular employees who are dedicated to the Customer Information System ("CIS") which I discuss further in my testimony.

Q. Please explain the increase of $30,000 as a non labor adjustment for abandoned projects.

A. This adjustment represents costs incurred for abandoned projects that are written off. The explanation for the abandoned project budget adjustment is provided by Ms. Patsy Nanbu in HECO T-10.

Q. What customer service functions are charged to Account No. 903?

A. Included in this account are the labor and non-labor expenses for:

1) handling customer calls and requests;
2) processing customer requests to start, change or terminate service;
3) maintenance of customer accounts within the Customer Information System

(ACCESS);

4) bill calculation;

5) printing and mailing of bills;

6) processing of customer payments; and

7) managing delinquent accounts and credit related activities.

Q. What functional areas budget and charge to Account No. 903?

A. Labor expenses are budgeted in Account No. 903 by the Administration Division, the Credit Division which includes Payment Processing, the Field Service & Collections Division (excluding the Meter Reading Section), and the Customer Account Services Division, which includes the Customer Accounting & Billing section and the Customer Assistance Center.

Q. How does the 2007 test year labor expense estimate for Account No. 903 compare with the 2005 recorded expense?

A. The test year labor expense estimate is $126,000 lower than the 2005 recorded labor expense.

Q. What is the reason for this decrease in the 2007 test year estimate from the 2005 recorded expense?

A. The reason for the decrease is the deferral of expenses associated with seven clerical and administrative staff assigned to the development of the database that will be used in HECO's new CIS system that I mentioned above.

Q. Please describe CIS.

A. CIS is a new customer information system that consists of the purchase and installation of hardware and software, including support system software, which will replace HECO's existing ACCESS customer information system. In Decision and Order No. 21798, dated May 3, 2005, issued by the Public Utilities

Commission in Docket No. 04-0268 ("CIS Order"), HECO's purchase and implementation of CIS was approved. The CIS Order also approved HECO's accounting treatment to defer certain computer software development costs, including database development costs. Thus, the labor costs for seven clerical and administrative staff who are dedicated to developing the database for CIS are deferred and not reflected as expense for the entire 2007 test year.

Q. Were any Customer Accounts' labor costs deferred in 2005 for CIS?

A. No. Labor expenses associated with the CIS project were deferred beginning 2006. This is the reason why labor expenses were higher in 2005 than in the test year.

Q. What costs are included in Account No. 903's $3,695,000 non-labor expense estimate for the test year 2007?

A. The 2007 test year non-labor expense includes costs for vehicle operation and maintenance, field service tools and equipment, seals, postage, maintenance of the different systems, e.g., Unisys, ACD/IVR , mV-90 and eBill, billing forms and envelopes, uniforms, miscellaneous supplies such as office supplies and printing and revised allocation of software maintenance and other data support services.

Q. How does the test year non-labor expense estimate for Account No. 903 compare with the 2005 recorded expense?

A. The test year non-labor expense is $451,000 higher than recorded 2005 non-labor expense.

Q. Please provide the reasons for the increase in the non-labor estimate over the 2005 recorded expense?

A. The primary reasons for the increase are the revised accounting allocation for software maintenance and software costs as discussed above and detailed in Ms.

Patsy Nanbu's testimony, HECO T-10, increases in postage costs that occurred in 2006 and scheduled for 2007, and the hiring of temporary agency staff to support the department's functions during the anticipated hiring "lag" period and while the CIS database is being developed..

ACCOUNT 904 – UNCOLLECTIBLE ACCOUNTS

Q. What is the test year 2007 expense estimate for Account No. 904 – Uncollectible Accounts Expense?

A. I am presenting three test year estimates of uncollectibles expense as shown in HECO-801 and HECO-805. These are:

1) $1,358,000, at present rates;
2) $1,411,000, at present rates with the interim surcharge as ordered in Interim Decision and Order No. 22050 in Docket No. 04-0113 (dated September 27, 2005); and
3) $1,511,000 at proposed rates.

Q. What is the reason for the three different test year estimates?

A. These three test year estimates were calculated to reflect the varying level of uncollectibles expense associated with the test year electric sales revenues estimated at present rates, at present rates with the interim surcharge, and proposed rates. The development of these revenue estimates is discussed by Mr. Peter Young in HECO T-3. Adjustments reflected in HECO-801, page 1, were made to the O & M budget to reflect these three different estimates of uncollectibles expense.

Q. Were the different estimates of electric sales revenues the only driver of all of the adjustments to the O & M budget?

A. No. The uncollectible factor used in the calculation of uncollectibles expense was also updated for the test year.

Q. Why was an uncollectible factor estimated specifically for the test year?

A. For the 2007 budget which was developed in early 2006, HECO used the uncollectible factor of 0.0946%, the factor that was agreed upon by all parties and approved by the Commission in Interim Decision and Order No. 22050 in Docket No. 04-0113 (dated September 27, 2005) for convenience. However, for the test year, HECO developed its own factor of 0.1009% based on the Company's most recently available recorded data, through August 2006 (HECO-WP-805). I discuss the development of the uncollectibles factor further in my testimony.

Q. Is the same uncollectible factor used in all three test year estimates?

A. Yes.

Q. Why does the Company calculate both the Uncollectible Accounts Expense between present rates and present rates with the interim surcharge?

A. The uncollectible accounts expense based on present rates and present rates with the interim surcharge are calculated as input into the Results of Operations presented by Mr. William Bonnet in HECO T-23. Further discussion regarding these presentations may be found in Mr. Bonnet's testimony.

Q. Which estimate of the uncollectible accounts expense is more representative of what the Company will experience in the test year?

A. The uncollectibles account expense that is currently being recorded by the Company is based on total revenues, i.e., present rates with the interim surcharge. Thus, the estimate of uncollectibles at present rates with the interim surcharge should be the closest to what the Company will actually experience in 2007.

Q. Why is there a difference in uncollectible accounts expense between present rates with the interim surcharge and proposed rates?

A. The 2007 test year estimate of uncollectibles differs between present rates with the interim surcharge and proposed rates because the electric sales revenues based on the proposed rates are higher than the present rates with the interim surcharge. The calculations for the estimated uncollectible amounts are shown on HECO-805.

Q. Please explain the general method used to determine the uncollectibles expense?

A. HECO uses the "Percentage of Electric Sales Revenue" method, as accepted by the Commission in previous dockets, including HECO's last two rate cases, in Interim Decision and Order No. 22050 in Docket No. 04-0113 (dated September 27, 2005) for the 2005 test year and Docket No. 7766 where the Commission issued Decision and Order No. 14412, dated on December 11, 1995, for the 1995 test year.

Q. What is the "Percentage of Electric Sales Revenue" method?

A. This method calculates uncollectibles for a given period by multiplying electric sales revenues for that period by a net write-off percentage. The net write-off percentage (or factor) is determined by dividing the total net write-offs for the latest twelve months for which write-off percentage data is available by the total electric sales revenue lagged by four months.

Q. What is the estimated net write-off percentage used to calculate test year 2007 uncollectibles?

A. The estimated net write-off percentage for 2007 test year is 0.1009%. (See HECO-WP-805, page 3).

Q. Why was a ten year time series used to calculate the 2007 uncollectibles?

A. Historically, write-offs fluctuate from year to year due to a number of external factors including bankruptcy filings, the economy, and increases in fuel prices. An example of a decelerating write-off period was in years 2004 and 2005 when the write-offs dipped to .03% from a relative stable period of near .10% from years 1999 through 2003. However, in the past several months the Company has experienced higher write-off levels, similar to those experienced in 2004 (HECO-WP-805). To reflect the long run uncollectibles experience of the Company, the data from the most recent 10 year period was used to estimate HECO's uncollectible rate (HECO-WP-805, page 3).

Q. How does the 0.1009% compare with other utilities?

A. Based upon a recent industry report by an industry resource, Datasource (a product of Edison Electric Institute and American Gas Association), the utility industry average in bad debt write-offs is .59% as shown in HECO-806 or nearly 6 times more than HECO's proposed rate of 0.1009%. HECO's results are significantly better than the industry average.

CUSTOMER DEPOSITS

Q. What is HECO's average test year estimate of customer deposits?

A. HECO's average test year estimate of customer deposits is $6,377,000, as shown in HECO-802.

Q. Why are customer deposits collected?

A. Customer deposits are collected from customers as security for their electric service. These customers are either new customers who have not established their creditworthiness with HECO, or are past or existing customers who have failed to maintain creditworthiness with us.

Q. When does HECO require a deposit?

A. A deposit is required in cases when the applicant for service cannot establish credit by any of the other means allowed under HECO Tariff Rule No. 5, Establishment and Re-establishment of Credit. The deposit is held until the customer has established a record of twelve months of continuous prompt payments, has closed the account, or service has been terminated for nonpayment of the full deposit and/or electric bills.

Q. Are there any changes proposed regarding customer deposits?

A. No.

Q. How was the test year estimate of customer deposits derived?

A. The test year's EOY estimate of customer deposits was derived by multiplying the 2006 estimated EOY customer deposit balance by a factor of 7.197%. The average test year estimate of customer deposits was derived from a simple average of the estimated year-end 2006 and 2007 customer deposit balances of $6,155,000 and $6,598,000, respectively.

Q. How was the factor of 7.197% derived?

A. The factor represents the average annual growth rate in year-end deposit balances for the period from 2001 through 2005, as shown in HECO-WP-802

Q. How was the projected year-end 2006 deposit balance derived?

A. The 2006 estimated year-end customer deposit balance was derived by dividing the calculated average growth rate of 7.197% by twelve to estimate a monthly growth rate of 0.59%. This monthly growth rate was then applied to the August 31, 2006, customer deposit balance to estimate the September 2006 balance. The monthly growth rate was then applied to this calculated balance to estimate the October balance in turn. The process was repeated until the December 2006 balance was estimated.

Q. How was the projected 2007 EOY deposit balance derived?

A. The 2007 EOY deposit balance was estimated by increasing the December 2006 estimated customer deposit balance of $6,155,000 by a factor of 7.197% for 2007, as shown in HECO-WP-802.

INTEREST ON CUSTOMER DEPOSITS

Q. What is HECO's test year estimate of Interest on Customer Deposits?

A. HECO's test year estimate of Interest on Customer Deposits is $375,000 as shown in HECO-803.

Q. How was the 2007 EOY balance estimate of Interest on Customer Deposits derived?

A. The 2007 EOY balance was estimated by multiplying the 2006 EOY balance estimate of $350,000 with the factor of 1.07197. This is the same annual growth rate factor calculated for customer deposits for 2007 as discussed above and is shown in HECO-WP-803. The 2006 amount was estimated in the same manner that was used to estimate the 2006 year-end customer deposit balance.

REVENUE LAG DAYS

Q. What level of revenue lag days is proposed for test year 2007?

A. The estimated revenue lag days for the test year are 37 days.

Q. What are revenue lag days?

A. Revenue lag days measure the amount of time between the date that electricity is used by the customer and the date that HECO is paid for such use.

Q. How did HECO calculate its test year estimate of revenue lag days?

A. The test year estimate of revenue lag days was calculated by adding a fixed number of days (representing the mid-point of the monthly bill) to a variable number that represents the average amount of time it takes to bill a customer and receive payment for the bill.

Q. What are these numbers of days for test year 2007?

A. The fixed days for the test year is 15.5; the variable days are 21.7.

Q. Is the proposed revenue lag days estimate for the test year 2007 reasonable?

A. Yes. Over the past ten years from 1996 to 2005, the actual average revenue lag days were 37.2 days as shown on HECO-WP-804, page 5.

NON-SALES ELECTRIC UTILITY CHARGES

Q. What non-sales electric utility charges do you cover in your testimony?

A. I am covering the Service Establishment Charge, Late Payment Charge, Field Collection Charge, and the Returned Check Charge as reflected in HECO-807 Mr. Bruce Tamashiro in HECO T-13 covers the other non-sales electric utility charges from the Payment Protection Program and from Purchase Power Metering charges.

Q. How are the revenues from non-sales electric utility charges determined?

A. The estimated revenues at present rates from the Service Establishment Charge, Field Collection Charge, and Returned Check Charge are based on the forecasted transaction levels for each type of charge for the 2007 test year as noted in HECO-WP-806, page 2, then multiplied by the rate charged by the Company as specified in the Rule No. 7, Sections C, D, and E of HECO's tariff, sheets 16 and 16A, and as reflected in HECO-WP-806, page 1.

Q. How were the transactions for these charges forecasted for the test year?

A. The number of transactions is equal to the average annual number of transactions for the past five years.

Q. Are there changes proposed to non-sales electric utility charges at proposed rates?

A. Yes. The Company is proposing the same changes to the Service Establishment Charge and the Field Collection Charge that it proposed in the 2005 HECO rate case in Docket No. 04-0113. For the Returned Payment Charge, HECO proposes to increase the charge to $22.00. In the 2005 HECO rate case, the Company proposed an increase to $16.00. The purpose of the proposed changes is to charge the customers who cause the costs to be incurred by the Company. The following are the proposed changes:

1) increase the Service Establishment Charge from $15.00 to $20.00, and increase the additional charge for the same day service or for service outside of the normal business hours from the current $10.00 to $25.00;
2) increase the Field Collection Charge from $15.00 to $20.00, and modify its application such that, the customer will be charged the Field Collection Charge even when a field call does not result in successful collection of monies; and
3) change the Returned Checks Charge to a Returned Payment Charge and increase the current charge from the current $7.50 to $22.00 per returned check or returned payment.

Q. Please explain how the proposed changes to the Field Collection Charge and Service Establishment Charge were determined.

A. Mr. Peter Young explains how the proposed rates were developed in HECO T-3.

Q. Please explain how the Field Collection Charge is currently applied.

A. HECO's current Field collection Charge is applied only when a field call results in actual collection of payment form the customer.

Q. What changes is HECO proposing in regard to the application of the Field Collection Charge?

A. HECO is proposing to apply the proposed Field Collection charge to every field collection call made regardless of whether a field collection call results in successful collection of payment from the customer. The Company incurs the same costs for every field collection call made regardless of whether or not it results in successful collection of payment from the customer. HECO has a Field collection procedure in place, which ensures that a field call is made only as a last resort or attempt to collect payment form the customer.

Q. Why is the Company proposing to change the "Returned Checks Charge" name to "Returned Payment Charge"?

A. The Company is proposing to change "Returned Checks Charge" to "Returned Payment Charge" to reflect the different payment options that are now available to customers, and to allow the Company to apply the same service charge on "returned" payments made through any of these options.

Q. What payment options are now available to the customers?

A. In the past, customers could pay their electric bill either by check or in cash. With the changes in technology, HECO offers customers different electronic bill payment options ("e-billing"). The various e-billing options that are available to HECO customers include the following:

1) Automatic Bill Payment (ABP) – automatically debits customer's savings or checking account;
2) payment using credit card; and
3) payment using debit card.

When payments made through any of these "paperless" payment options are "returned" due to insufficient funds in the customers' accounts, the bank charges HECO a service charge for the processing cost – similar to a bounced check processing fee. For fairness and equity, HECO is proposing to change the Returned Checks Charge to Returned Payment Charge and to apply it to any "returned" payment from any of the "paperless" payments in addition to returned checks. The proposed change will charge the cost of such returned payments to those customers who cause such costs to be incurred by HECO, rather than shifting those costs to the other ratepayers.

Q. Why is the proposed charge higher than what the Company proposed in the 2005 rate case?

A. Because the banks have recently increased their charges to the Company for processing returned payments, the returned payment charges to cost causers should also be increased.

Q. How was the proposed Returned Payment Charge of $22.00 per returned payment determined?

A. Mr. Peter Young discusses the development of the proposed rate for Returned Payment Charge in HECO T-3.

Q. How are the Late Payment Charge revenues calculated?

A. The Late Payment Charge revenues are calculated by multiplying the estimated test year late payment charge factor and the estimated electric sales revenues developed with present rates, present rates with the interim surcharge, and the proposed rates.

Q. How was the Late Payment Charge percentage factor determined?

A. The Late Payment Charge percentage factor of 0.095 percent of electric sales revenues is calculated as the historical proportion of annual revenues from late payment charges to the total billed revenues during the period from year 2000 through 2005 as shown on HECO-WP-807.

Q. How was the Late Payment Charge estimated for OCARS (Other Customer Account Receivables – non Light & Power)?

A. The amount used was based on a review of historical payments from 2000 through 2005 as shown on HECO-WP-807.

Q. Who provided the estimates of electric sales revenues at present rates, present rates with the interim surcharge, and proposed rates?

A. Mr. Peter Young provided these estimates and discusses their development in HECO T-3.

SUMMARY

Q. Please summarize your testimony.

A. The 2007 test year estimate for Customer Accounts Expense is $13,378,000 at present rates, $13,431,000 at present rates with the interim surcharge, and $13,531,000 at proposed rates. This level of expense reflects the level of staffing (labor expense) and corresponding non-labor expenses that are required to provide service to customers each day. The test year level of spending also reflects HECO's continued effective management of delinquent accounts and bad debt, supports the ongoing technology and system enhancements and upgrades, and provides the level of miscellaneous expenses needed to provide good service to our customers.

The 2007 test year estimate for Customer Deposits is a simple average of year-end 2006 and 2007 estimated customer deposit balances of $6,155,000 and $6,598,000, respectively. The Interest on Customer Deposits for 2007 test year is

$375,000. The revenue collection lag days for the test year are 37 days. Revenues from non-sales electric utility charges at present rates, present rates with the interim surcharge, and proposed rates for the 2007 test year are $2,202,100, $$2,251,500, and $3,021,300 respectively. Finally, the Company proposes changes to the service-related charges including Service Establishment Charge, Field Collection Charge and Returned Checks Charge.

Q. Does this conclude your testimony?

A. Yes.

HAWAIIAN ELECTRIC COMPANY, INC.

DARREN S. YAMAMOTO

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 900 Richards Street, Honolulu, HI 96813
POSITION:	Manager, Customer Service Department Hawaiian Electric Company, Inc. (December 2004 to present)
YEARS OF SERVICE:	22 Years
EDUCATION:	University of Hawaii (1983), Bachelor of Business Administration, Finance
PREVIOUS POSITIONS:	Director, Customer Field Services, Customer Service Department Hawaiian Electric Company, Inc. (September 2002 to December 2004)
	Supervisor, Construction & Maintenance Department Hawaiian Electric Company, Inc. (November 1999 to September 2002)
	Working Foreman, Construction & Maintenance Department Hawaiian Electric Company, Inc. (October 1995 to November 1999)
	Transmission & Distribution Line Inspector, Construction & Maintenance Department Hawaiian Electric Company, Inc. (May 1994 to September 1995)
	Linemen, Construction & Maintenance Department Hawaiian Electric Company, Inc. (August 1984 to May 1994)

HAWAIIAN ELECTRIC COMPANY, INC.
CUSTOMER ACCOUNTS EXPENSE
2001 - 2007

($ THOUSANDS)

	RECORDED					BUDGET		ADJUST	TEST YEAR BUDGET
CUSTOMER ACCOUNTS	**2001**	**2002**	**2003**	**2004**	**2005**	2006	2007		2007
901.00 Supervision	329	633	620	856	973	1,060	1,358		1,358
902.00 Meter Reading Expenses	2,196	2,114	2,085	2,413	2,192	2,545	2,693		2,693
903.00 Cust Records & Collection	6,811	6,405	6,335	7,049	7,644	7,522	7,950	19	7,969
905.00 Misc. Customer Accounts	3	2	0	1	1	0	0		0
Subtotal less Uncollectible Acct.	9,339	9,154	9,040	10,319	10,810	11,127	12,001	19	12,020
904.00 Uncollectible Accounts	774	737	1,015	413	339	1,053	1,363	(5)	1,358
Total Customer Account Expense **Present Rates**	10,113	9,891	10,055	10,732	11,149	12,180	13,364	14	13,378
904.00 Uncollectible Accounts	774	737	1,015	413	339	1,053	1,363	48	1,411
Total Customer Account Expense **Present Rates with Interim Surcharge**	10,113	9,891	10,055	10,732	11,149	12,180	13,364	67	13,431
904.00 Uncollectible Accounts	774	737	1,015	413	339	1,053	1,363	148	1,511
Total Customer Account Expense @ **Proposed Rates**	10,113	9,891	10,055	10,732	11,149	12,180	13,364	167	13,531

Source: HECO-WP-101 (B), Reports S1 and S2 for Recorded 2001 to 2005 and Budget 2006 and 2007 amounts.

HAWAIIAN ELECTRIC COMPANY, INC.
CUSTOMER ACCOUNTS EXPENSE
2001 - 2007

($ THOUSANDS)

		RECORDED					FORECAST			TEST YEAR
LINE	CUSTOMER ACCOUNTS	2001	2002	2003	2004	2005	2006	2007	ADJUST	2007
	Account 901 - Supervision									
1	Labor	71	56	60	43	80	165	154		154
2	Non-labor	258	577	560	813	893	895	1,204		1,204
3	TOTAL	329	633	620	856	973	1,060	1,358		1,358
	Account 902 - Meter Reading									
4	Labor	1,778	1,717	1,847	1,963	1,852	2,152	2,237		2,237
5	Non-labor	418	397	238	450	340	393	456		456
6	TOTAL	2,196	2,114	2,085	2,413	2,192	2,545	2,693		2,693
	Account 903 - Cust Rec. & Collection									
7	Labor	3,657	3,647	3,724	4,012	4,400	4,508	4,348	(74)	4,274
8	Non-labor	3,154	2,759	2,611	3,037	3,244	3,014	3,602	93	3,695
9	TOTAL	6,811	6,406	6,335	7,049	7,644	7,522	7,950	19	7,969
	Account 905 - Misc Cust Accts.									
10	Labor	3	2	0	1	1	0	0		0
11	Non-labor									
12	TOTAL	3	2	0	1	1	0	0		0
	Sub total 901,902,903,905									
13	Labor	5,509	5,422	5,631	6,019	6,333	6,825	6,739	(74)	6,665
14	Non-Labor	3,830	3,733	3,409	4,300	4,477	4,302	5,262	93	5,355
15	TOTAL	9,339	9,155	9,040	10,319	10,810	11,127	12,001	19	12,020
	Account 904 - Uncollectible Accts.									
16	Non-labor	774	736	1,015	413	339	1,053	1,363	(5)	1,358
17	TOTAL	774	736	1,015	413	339	1,053	1,363	(5)	1,358
	Total Cust. Accts Present Rates									
18	Labor	5,509	5,422	5,631	6,019	6,333	6,825	6,739	(74)	6,665
19	Non-labor	4,604	4,469	4,424	4,713	4,816	5,355	6,625	88	6,713
20	TOTAL	10,113	9,891	10,055	10,732	11,149	12,180	13,364	14	13,378
	Account 904 - Uncollectible Accts.									
21	Non-labor	774	736	1,015	413	339	1,053	1,363	48	1,411
22	TOTAL	774	736	1,015	413	339	1,053	1,363	48	1,411
	Total Cust. Accts Present Rates with Interim Surcharge									
23	Labor	5,509	5,422	5,631	6,019	6,333	6,825	6,739	(74)	6,665
24	Non-labor	4,604	4,469	4,424	4,713	4,816	5,355	6,625	141	6,766
25	TOTAL	10,113	9,891	10,055	10,732	11,149	12,180	13,364	67	13,431
	Account 904 - Uncollectible Accts.									
26	Non-labor	774	736	1,015	413	339	1,053	1,363	148	1,511
27	TOTAL	774	736	1,015	413	339	1,053	1,363	148	1,511
	Total Cust. Accts Proposed Rates									
28	Labor	5,509	5,422	5,631	6,019	6,333	6,825	6,739	-74	6,665
29	Non-labor	4,604	4,469	4,424	4,713	4,816	5,355	6,625	241	6,866
30	TOTAL	10,113	9,891	10,055	10,732	11,149	12,180	13,364	167	13,531

Source: HECO-WP-101 (B), Reports S1 and S2 for Recorded 2001-2005 and Budget 2006 & 2007 amounts.

HAWAIIAN ELECTRIC COMPANY, INC.

CUSTOMER DEPOSITS

(ACCOUNT 235.01)

($ THOUSANDS)

Line		
1	Recorded Balance 12/31/01	4,183
2	Recorded Net Increase in 2002	300
3	Recorded Balance 12/31/02	4,483
4	Recorded Net Increase in 2003	589
5	Recorded Balance 12/31/03	5,072
6	Recorded Net Decrease in 2004	-6
7	Recorded Balance 12/31/04	5,066
8	Recorded Net Increase in 2005	321
9	Recorded Balance 12/31/05	5,387
10	Estimated Net Increase in 2006	768
11	Estimated Balance 12/31/06	6,155
12	Estimated Net Increase in 2007	443
13	Estimated Balance 12/31/07	6,598
	Estimated Balance 12/31/06	6,155
	Estimated Balance 12/31/07	6,598
		12,753 /2
		6,377

Source: HECO-WP-802

HAWAIIAN ELECTRIC COMPANY, INC.

INTEREST ON CUSTOMER DEPOSITS

(ACCOUNT 431.05)

($ THOUSANDS)

Line		
1	Recorded Balance 12/31/01	236
2	Recorded Net Increase in 2002	26
3	Recorded Balance 12/31/02	262
4	Recorded Net Increase in 2003	18
5	Recorded Balance 12/31/03	280
6	Recorded Net Increase in 2004	39
7	Recorded Balance 12/31/04	307
8	Recorded Net Increase in 2005	2
7	Recorded Balance 12/31/05	309
8	Estimated Net Increase in 2006	41
9	Estimated Balance 12/31/06	350
10	Estimated Net Increase in 2007	25
11	Estimated Balance 12/31/07	375

Source: HECO-WP-803

HAWAIIAN ELECTRIC COMPANY, INC.
Summary Recorded and Average Number of Employees

	2004 Recorded EOY	2004 Average	2005 Recorded EOY	2005 Average	2006 YTD Recorded 9/30/06	2006 Projected EOY	2007 EOY Test Year	2007 Test Year Average
Sr. VP Operations	2	2	3	2	3	3	3	3
Customer Service	126	118	130	129	125	126	133	131
TOTAL	128	120	133	131	128	129	136	134

Source: HECO-1403

HAWAIIAN ELECTRIC COMPANY, INC.

UNCOLLECTIBLE ACCOUNTS EXPENSE

2007

ACCOUNT 904

($ THOUSANDS)

Line		Estimated Test Year Revenue 2007
1	Electric Sales Revenue used for 2007 BUDGET	$1,441,000
2	Times Uncollectible Factor used for 2007 Budget	0.0946%
3	Equals Uncollectible Accounts Expense	$1,363
4	Electric Sales Revenue at Present Rates* (without interim surcharge)	$1,346,000
5	Times Uncollectible Factor	0.1009%
6	Equals Uncollectible Accounts Expense	$1,358
7	Electric Sales Revenue at Present Rates* (with interim surcharge)	$1,398,000
8	Times Uncollectible Factor	0.1009%
9	Equals Uncollectible Accounts Expense	$1,411
10	Electric Sales Revenue at Proposed Rates	$1,497,100
11	Times Uncollectible Factor	0.1009%
12	Equals Uncollectible Accounts Expense	$1,511

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Xcel Energy C	0.38
Memphis C	0.38
Consumers En C	0.37
N J Natural G	0.33
AEP E	0.31
PS of NH E	0.31
Entergy C	0.30
Savannah E	0.29
TECO E	0.29
LG&E C	0.28
Northwestern SDNE C	0.28
N W Natural G	0.25
PG&E C	0.24
Newfoundland Pow E	0.24
Progress Car E	0.23
Alabama Pow E	0.23
Northwestern MT C	0.23
Duke E	0.22
Kentucky Ut E	0.17
Sierra Pac C	0.17
Miss Pow E	0.16
Fl P&L E	0.16
S Cal Edison E	0.13
Arizona PS E	0.12
GazMetro G	0.08
Hawaiian E	0.03
Average	**0.59**
59 Responses	
No Response 0%	

111,191. Net Write-offs Percent of Revenue (calculated Net Write-off above / (Q110819+Q110831) -- 2004 *View Full Screen* *Summary by Co Type*

Equitable G	2.79
KeySpan NE G	1.96
Duquesne Light E	1.88

HAWAIIAN ELECTRIC COMPANY, INC.
2007 TEST YEAR

NON-SALES ELECTRIC UTILITY CHARGES

	At Present Rates	with interim surcharge At Present Rates	At Proposed Rates
Non-Sales Electric Utility Charges			
Service Establishment Charges	$791.0	$791.0	$1,149.0
Field Collection Charges	$88.9	$88.9	$332.2
Returned Check(Payment) Charges	$38.5	$38.5	$112.9
Late Payment Charges - OCARS	$5.0	$5.0	$5.0
Late Payment Charges	$1,278.7	$1,328.1	$1,422.2
Total Other Operating Revenues	**$2,202.1**	**$2,251.5**	**$3,021.3**